IEPR Committee Workshop on the Cost of Electricity Generation

Levelized Cost of Generation Model - Renewable Energy, Clean Coal and Nuclear Inputs

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NAVIGANT CONSULTING

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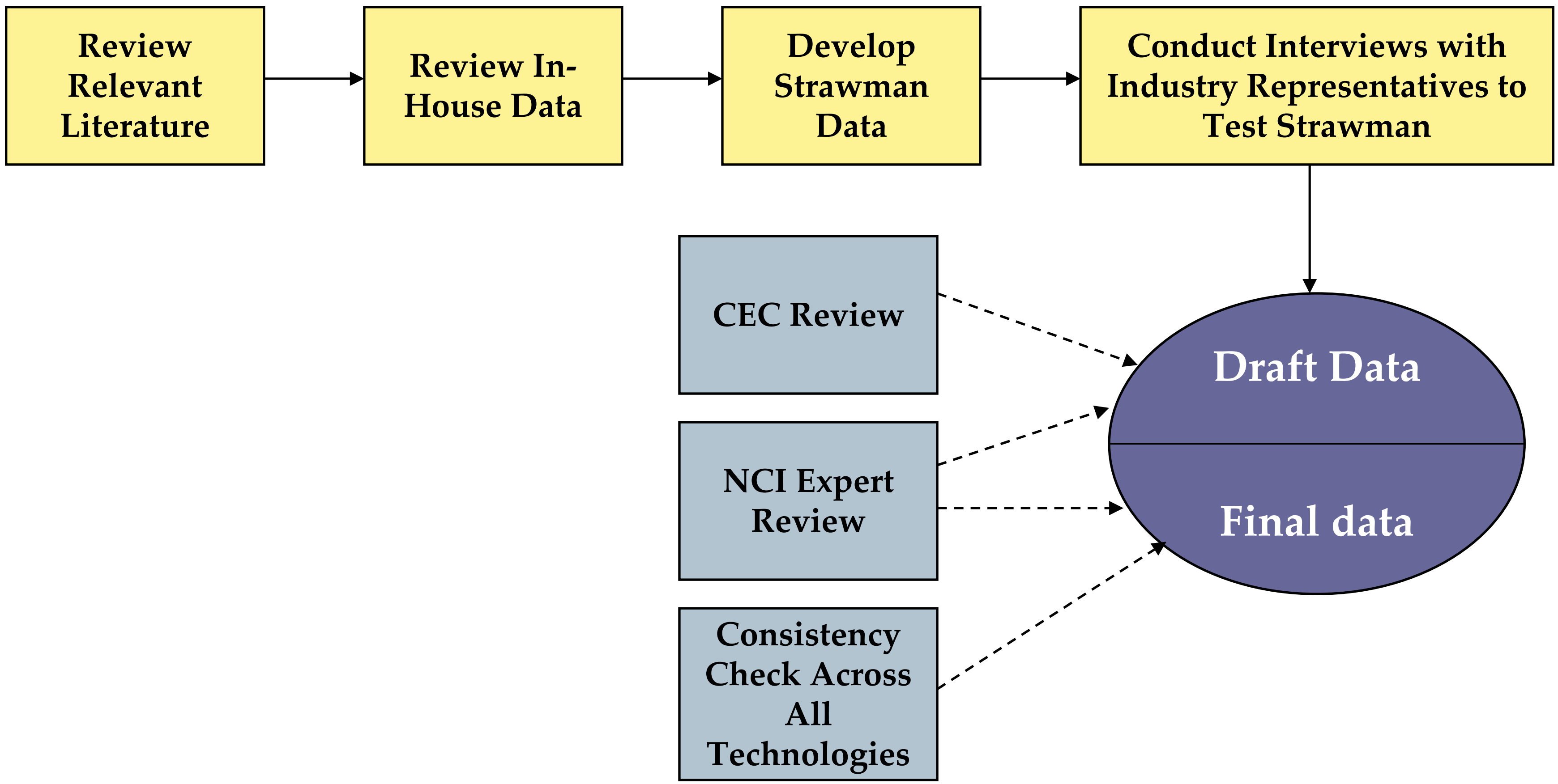
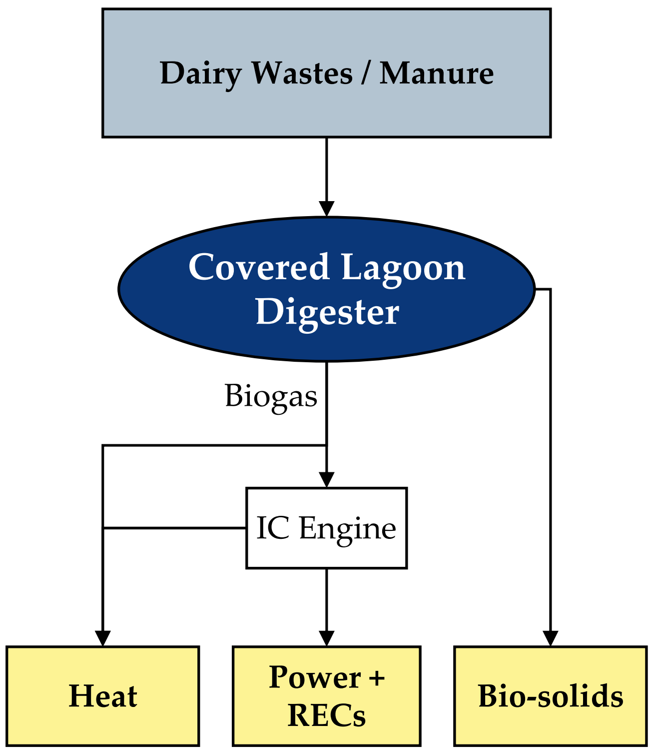
NCI Process for Inputs to IEPR Model

NCI reviewed existing literature and in-house data to develop strawman information that was then vetted with industry.



An anaerobic digester treats dairy manure to produce biogas that can be used to produce electricity, heat, and bio-solids.

Schematic of the Technology



Description

- An anaerobic digester utilizes the natural process of anaerobic decomposition to treat waste (e.g. dairy cow manure), produce biogas that can be used to power electricity generators, provide heat and produce soil improving material.
- Anaerobic Digestion Power Production with an IC Engine is an established technology.
- These cost estimates assume a combined heat and power internal combustion engine.
- Costs can vary depending on the digester being deployed. These cost estimates are for a **covered lagoon**, which is the cheapest, most suitable for warm climates.
- Other conventional digester technologies are Plug-Flow (rectangular flow-through tank, 11-13% solids), and Complete Mix (large tanks, 10% solids, most expensive).
- Other more advanced digester technologies use "multi-stage" digesters or "flow" designs with the use of "thermophillic" (high temperature) bacteria.

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Economic Assumptions: Anaerobic Digesters – Dairy

	Anaerobic Digesters – Dairy Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (kW)	250	A 250 kW system is the expected size of new single-farm, covered lagoon anaerobic digester in CA. Sizes may increase over time if other types of organic wastes are added.
Project Life (yrs)	20	From Navigant Consulting sources and estimates.
Overnight Cost ($/kW)	$5,300	Overnight costs includes development fees, interconnection, but not interest during construction. The cost breakdown between engine/generator, digester and other is an approximation, and is performed differently by each source. The digester component could also be considered installation.
Electrical Facilities ($/kW)	$2,000	From Navigant Consulting sources and estimates.
Digester ($/kW)	$2,600	From Navigant Consulting sources and estimates.
Other ($/kW)	$700	Other includes manure storage, liquids separation; and varies depending on system design.
Fixed O&M ($/kW-yr)	$50	O&M costs are estimated to be near $250/kW-yr in California based on cost estimates at actual facilities. These costs are not typically separated into fixed and variable. NCI estimates that 80% of the costs are variable. These numbers have been confirmed by interviews.
Variable O&M ($/MWh)	$15	

Sources: Navigant Consulting Estimates 2007, Cornell Manure Management Program, California Dairy Power Production Program, Wisconsin Anaerobic Digester Casebook – 2004 Update, NCI Interviews with equipment and digester manufacturers.

Performance Data: Anaerobic Digesters – Dairy

	Anaerobic Digesters – Dairy Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Typical Net Capacity Factor (%)	75%	Capacity Factors can vary significantly by dairy and can be dependent on the owner's motivation or amount paid for an O&M service contract.
Fuel Cost ($/MMBtu)	n/a	
Economic Benefits from by-products sales (heat, digester solids) ($/kW-yr)	$100	Economic Benefits can vary significantly, but based on historical data can amount to $20,000/yr for a 200 kW system.
HHV Efficiency (%)	20%	HHV Efficiency is based on the feedstock to electricity. Feedstock to methane is typically 60% to 70% efficient and the IC engine ~30%.
CO_2 (lb/MWh)	AD – Dairy is assumed to be CO_2 neutral. SB 1368 contains provisions recognizing the net emission, whole-fuel cycle character of Biomass.	
NO_x (lb/MWh)	1.7	NO_x can vary widely. Figures shown assume 60 ppmv @15% O_2 in exhaust, which complies with the CARB guidelines for BACT.
SO_x (lb/MWh)	0.39	Sulfur content can vary. Figures shown assume SO_2 in exhaust of 10 ppmv @ 15% O_2.

Sources: Navigant Consulting Estimates 2007, Cornell Manure Management Program, California Dairy Power Production Program, Wisconsin Anaerobic Digester Casebook – 2004 Update, NCI Interviews with equipment and digester manufacturers.

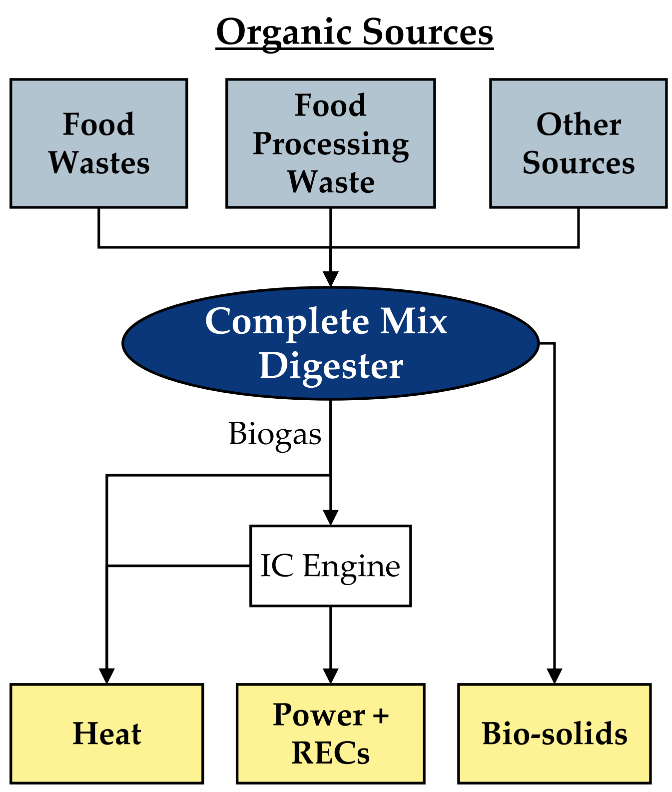
Methodology and Key Assumptions: Anaerobic Digesters – Dairy

Methodology & Key Assumptions

- The costs are for a standard covered lagoon digester. Most systems in California use a covered lagoon. In the future, more and more systems will utilize a complete mix system or other technology that allows multiple feedstocks to be placed in the digester. This technology is described in the "Anaerobic Digester – Food Waste"
- NCI surveyed costs from public– California's Dairy Power Production Program, California's Western United Dairymen, Wisconsin's Agricultural Biogas Casebook, and Cornell University's Manure Management Program. We developed installed cost and O&M based on these sources and confirmed these estimates with interviews with system designers, installers, and equipment providers. Installed costs in California are likely to be higher than the Midwest due to higher labor costs for the construction of the digester and installation of the equipment.
- Actual costs for a covered lagoon digester can vary by 25% depending on foundation and lining requirements for the digester as well as local labor rates.
- Costs for complete mix systems with concrete-lined digesters can cost approximately $700/kW more. These systems are more common on the east coast where manure is scraped into the digesters. In California, it is much more common to wash manure away with water. A covered lagoon system is more adequate for these systems given the moisture content.
- Costs for larger, 1 MW systems can cost 25% less due to economies of scale..
- Future costs are not expected to decrease in real terms as the total cost is driven primarily by installation costs and materials. Future cost declines for both installed costs and O&M are driven by reduced costs for the IC engine.

An anaerobic digester treats food wastes manure to produce biogas that can be used to produce electricity, heat, and bio-solids.

Schematic of the Technology



Description

- An anaerobic digester utilizes the natural process of anaerobic decomposition to treat waste (e.g. food wastes), produce biogas that can be used to power electricity generators, provide heat and produce soil improving material.
- These cost estimates assume a combined heat and power internal combustion engine.
- Food wastes could include:
  - Food wastes, from large food retail establishments
  - Fats, oils and grease (FOGs), such as Yellow Grease or trap greases
  - Food processing wastes
- Costs can vary depending on the digester being deployed. These cost estimates are for a **Complete Mix,** which deploys large tanks, has 10% solids, and is the most expensive of the conventional digester technologies.

Economic Assumptions: Anaerobic Digesters - Food Waste

	Anaerobic Digesters - Food Waste Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (kW)	2,000	The Plant Capacities will vary widely. There is the potential for capacities to increase in the future as technology advances allow for additional types of feedstocks to be combined and utilized.
Project Life (yrs)	20	From Navigant Consulting sources and estimates.
Overnight Cost ($/kW)	$5,300	Total installed costs will vary widely depending on size, number and type of feedstocks, type and use of electricity generating equipment. In many applications, the biogas may be used for process heat or for pipeline quality natural gas.
Electrical Facilities ($/kW)	$1,750	From Navigant Consulting sources and estimates.
Digester ($/kW)	$2,100	
Other ($/kW)	$1,450	
Fixed O&M ($/kW-yr)	$150	Fixed O&M is estimated to be approximately $150/kW-yr. Variable O&M is estimated to be $200/MWh. Economic Benefits offset Variable O&M costs by $20/wet ton **tipping fee** at food waste moisture content of 80%, and $75/kW-yr for soil amendment resulting in a net Variable O&M cost of -$87/MWh.
Variable O&M ($/MWh)	-$87	

Sources: Navigant Consulting Estimates 2007, NCI Estimates for Anaerobic Digester-Dairy, NCI Interview with Dave Konwinski – Onsite Power Systems, NCI interviews with European project developers, owners, and technology providers.

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Performance Data: Anaerobic Digesters - Food Waste

	Anaerobic Digesters - Food Waste Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Typical Net Capacity Factor (%)	75%	Capacity Factors can vary significantly by plant and are largely dependent on the type of feedstock.
HHV Efficiency (%)	18%	HHV Efficiency is based on the feedstock to electricity. Feedstock to methane is typically 60% to 70% efficient and the IC engine ~30%. There is about a 10% loss in energy output to power the digester and mixing equipment.
CO_2 (lb/MWh)	AD – Food Waste is assumed to be CO_2 neutral. SB 1368 contains provisions recognizing the net emission, whole-fuel cycle character of Biomass.	
NO_x (lb/MWh)	1.7	NO_x can vary widely. Figures shown assume 55 ppmv @15% O_2 in exhaust, which complies with the CARB guidelines for BACT.
SO_x (lb/MWh)	0.42	Sulfur content can vary. Figures shown assume SO_2 in exhaust of 10 ppmv @ 15% O_2.

Sources: Navigant Consulting Estimates 2007, NCI Estimates for Anaerobic Digester-Dairy, NCI Interviews with industry players.

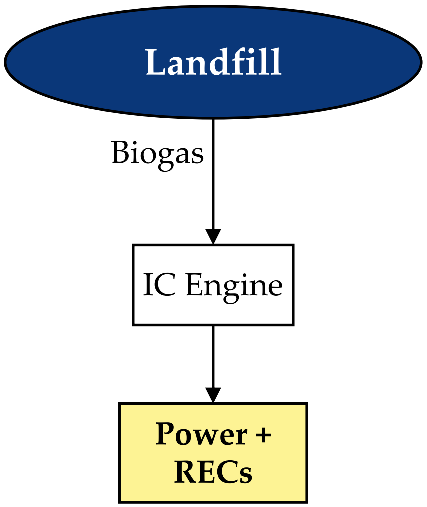
Methodology and Key Assumptions: Anaerobic Digesters - Food Waste

Methodology & Key Assumptions

- The cost estimates are for a complete-mix digester that could utilize a variety of organic wastes. Several different designs and technologies can be used, and the assumption for this technology is that one or two sources of primarily urban wastes are being used, e.g. food wastes from restaurants, organic waste separated at the landfill, or food processing wastes.
- The added complexity of the system requires additional staff to operate the facility and added capital equipment for preparation of the waste.
- Due to the increased size, the system benefits from economies of scale for the generation equipment and the digesters themselves.
- Future costs are expected to decline as designers and manufacturers of the digesters learn and optimize the design. As designs improve, an increased amount of organic waste may be included, and sizes could increase. These cost estimates assume a constant 2 MW size.
- Actual installed costs for existing facilities are not published in detail. Dave Konwinski from Onsite Power Systems provided guidance on cost data. NCI based its cost estimates on relative costs to a covered lagoon system, published costs for complete-mix systems, historical analysis based on systems in Europe, and input from Dave Konwinski.

A landfill gas fuel to energy (LFGFTE) utilizes the biogas from a landfill to power an electricity generator.

Schematic of the Technology



Description

- A landfill gas fuel to energy (LFGFTE) utilizes the biogas produced by decomposing organic waste in landfills to power an electricity generator.
- Since most applications use an internal combustion engine, these cost estimates assume a power-only internal combustion engine (no heat capture / CHP).
- IC Engines are more forgiving of the typically poor fuel quality that comes from a landfill.
- Costs can vary significantly based on the size of the application and the amount of front-end gas clean-up and tail-end emission clean-up. These cost estimates assume both front-end gas clean-up and tail-end emission clean-up due to the increasing stringency of California air emission regulations.

Economic Assumptions: Landfill Gas to Energy (LFGTE)

	Landfill Gas to Energy Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (kW)	2,000	The average size of existing facilities in CA is 4 MW. 32 of 51 of existing facilities in 2002 used a reciprocating engine, averaging 3.5 MW. The average size of future facilities using reciprocating engines is 2 MW.
Project Life (yrs)	20	From Navigant Consulting sources and estimates.
Overnight Cost ($/kWpac)	$1,850	Total Installed Costs for LFG have increased significantly over the past 5 years. According to CEC reports, historical costs as of 2002 were between $1,100/kW and $1,300/kW in CA. Based on interviews installed costs in 2006 are estimated to be 50% higher, primarily due to the increased cost in permitting costs and increased capital costs for emissions control.. Gas collection facilities are required to be in place for MSW facilities with design capacities over 2.75 Million tons. If they need to be added, they typically cost $500/kW.
Non-Fuel Fixed O&M ($/kW-yr)	$20	Historical O&M costs are based on historical costs at existing facilities as obtained from Energy Velocity as well as interviews with industry. The variable O&M includes only the maintenance of the generating equipment and not the maintenance of the landfill collection system, which is estimated to be about $50/kW-yr (10% of the installed cost of the gas collection system each year).
Non-Fuel Variable O&M ($/MWh)	$15	

Sources: Navigant Consulting Estimates 2007. “Landfill gas-to-energy potential in California”, CEC 500-02-041V1; “Economic and Financial Aspects of Landfill Gas to Energy Project Development in California”, Apr 2002, CEC-500-02-020; NCI Interviews; Energy Velocity; "Gas-fired Distributed Energy Resource Technology Characterizations", DOE/NREL/GTI, October 2003.

Performance Data: Landfill Gas to Energy (LFGTE)

	Landfill Gas to Energy Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Scheduled Outage Factor (%)	6%	Forced outage rates and typical capacity factors are based on historical data at existing plants as reported by Energy Velocity.
Forced Outage Rate (%)	7%	
Typical Net Capacity Factor (%)	85%	
Fuel Cost ($/MMBtu)	-	
HHV Efficiency (%)	29.5%	From Navigant Consulting sources and estimates.
CO_2 (lb/MWh)	LFGTE is assumed to be CO_2 neutral. SB 1368 contains provisions recognizing the net emission, whole-fuel cycle character of Biomass.	
NO_x (lb/MWh)	1.7	Figures shown assume 65 ppmv @15% O_2 in exhaust, which complies with the CARB guidelines for BACT.
SO_x (lb/MWh)	0.34	Figures shown assume SO_2 in exhaust of 10 ppmv @ 15% O_2.

Sources: Navigant Consulting Estimates 2007. "Landfill gas-to-energy potential in California", CEC 500-02-041V1; "Economic and Financial Aspects of Landfill Gas to Energy Project Development in California", Apr 2002, CEC-500-02-020; NCI Interviews; Energy Velocity; "Gas-fired Distributed Energy Resource Technology Characterizations", DOE/NREL/GTI, October 2003.

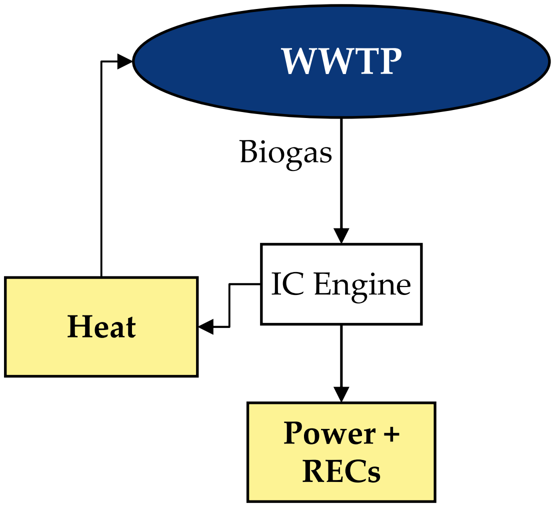
Methodology and Key Assumptions: Landfill Gas to Energy (LFGTE)

Methodology & Key Assumptions

- Landfill gas to energy systems come in a wide variety of sizes and use a variety of different generating equipment. For the purpose of this analysis, the costs are based on a 2 MW reciprocating engine, which has been a common common system historically, and many of the planned systems are expected to be similar. Fuel cells and microturbines may become more pervasive as emission requirements become more stringent and the cost of these technologies decreases.
- The costs of landfill gas to energy facilities in California have increased from about $1,200/kW in 2002 to about $1,850/kW in 2006. Actual costs for installed systems varies widely due to the differences in technology, size, accounting, and cost overruns. NCI based its estimates for installed costs on its own historical cost estimates, historical costs published by the CEC, as well as interviews with owners and developers of landfill gas to energy projects.
- The increase in cost has been driven by more stringent permitting requirements that has increased the development costs and increased capital costs for emission control equipment.
- Costs for the electric generating equipment (i.e. reciprocating engine) are expected to decline by about 1%/yr based on interviews as well as DOE/NREL projections. Development costs and installation costs are expected to remain constant in real terms as these are driven more by labor and permitting.
- The variable O&M includes only the maintenance of the generating equipment and not the maintenance of the landfill collection system, which is estimated to be about $50/kW-yr (10% of the installed cost of the gas collection system annually, or approximately $50/kW-yr)

A waste water treatment fuel to energy (WWTFTE) facility utilizes the biogas produced at a waste water treatment facility to power an electricity generator and produce heat.

Schematic of the Technology



Description

- A waste water treatment fuel to energy (WWTFTE) facility utilizes the biogas produced by decomposing organic waste in a waste water treatment facility to power an electricity generator and produce heat.
- Since most applications use an internal combustion engine, these cost estimates assume a combined heat and power internal combustion engine.
- IC Engines are more forgiving of the typically poor fuel quality that comes from a waste water treatment facility.
- Costs for a WWTFTE facility are typically higher than a LFGTE due to the smaller size of the engine, and the additional costs of the heat capture / CHP. These cost estimates assume both front-end gas clean-up and tail-end emission clean-up due to the increasing stringency of California air emission regulations.

Economic Assumptions: Waste Water Treatment Fuel to Energy (WWTFTE)

	Waste Water Treatment Fuel to Energy Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (kW)	500	From Navigant Consulting sources and estimates.
Project Life (yrs)	20	
Overnight Cost ($/kWpac)	$2,400	Costs for a WWTFTE facility are typically higher than a LFGTE due to the smaller size of the engine, and the additional costs of the heat capture/CHP.
Fixed O&M ($/kW-yr)	$22	Historical O&M costs are based on historical costs at existing facilities as obtained from Energy Velocity as well as interviews with industry. O&M costs are higher for the WWTFTE than the LFGTE due to the decreased scale.
Variable O&M ($/MWh)	$18	

Sources: Navigant Consulting Estimates 2007. NCI cost estimates 2002-2006, NCI Interviews; Energy Velocity; "Gas-fired Distributed Energy Resource Technology Characterizations", DOE/NREL/GTI, October 2003.

Performance Data: Waste Water Treatment Fuel to Energy (WWTFTE)

	Waste Water Treatment Fuel to Energy Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Scheduled Outage Factor (%)	6%	Forced outage rates and typical capacity factors are based on historical data at existing plants as reported by Energy Velocity.
Forced Outage Rate (%)	7%	
Typical Net Capacity Factor (%)	85%	
Fuel Cost ($/MMBtu)	-	
HHV Efficiency (%)	27.5%	From Navigant Consulting sources and estimates.
CO_2 (lb/MWh)	WWTFTE is assumed to be CO_2 neutral. SB 1368 contains provisions recognizing the net emission, whole-fuel cycle character of Biomass.	
NO_x (lb/MWh)	1.7	Figures shown assume 65 ppmv @15% O_2 in exhaust, which complies with the CARB guidelines for BACT.
SO_x (lb/MWh)	0.39	Sulfur content of WWTP can vary. Figures shown assume SO_2 in exhaust of 10 ppmv @ 15% O_2. For SO_x this value is consistent with some H_2S removal prior to combustion.

Sources: Navigant Consulting Estimates 2007. Navigant Consulting Estimates 2007. NCI cost estimates 2002-2006, NCI Interviews; Energy Velocity; "Gas-fired Distributed Energy Resource Technology Characterizations", DOE/NREL/GTI, October 2003.

Methodology and Key Assumptions: Waste Water Treatment Fuel to Energy (WWTFTE)

Methodology & Key Assumptions

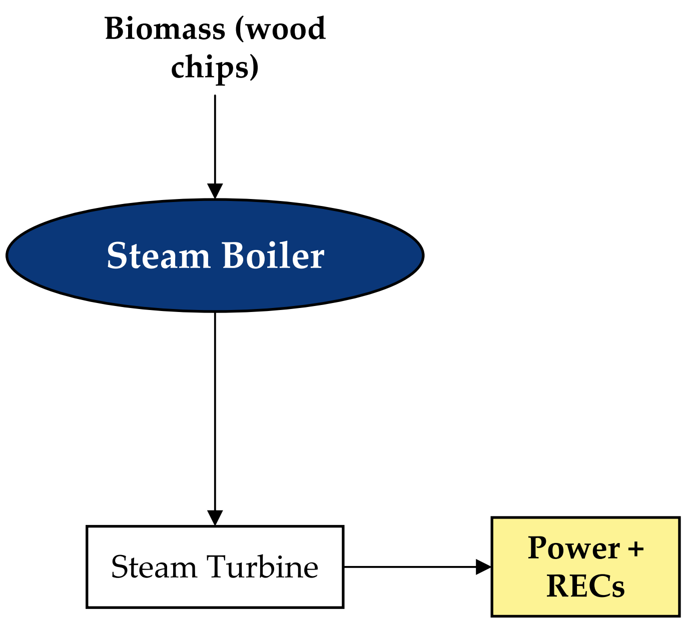
- The costs of a wastewater treatment fuel to energy (WWTFTE) system will be very similar to that of a LFGTE system. The configurations are fairly similar, but the WWTFTE system will have higher installed costs because it is a smaller system and it is a CHP application.
- The O&M for a WWTFTE system does not include the O&M for the gas collection system.
- There are limited sources for historical costs of WWTFTE systems. The estimates are based on historical NCI estimates and interviews. We also confirmed the difference in capital costs due to CHP and size with DOE/NREL estimates.

Technology Profiles

- Biomass - Biogas
- **Biomass – Combustion**
- Biomass – Gasification (BIGCC)
- Geothermal
- Hydro
- Concentrating Solar
- Photovoltaics
- Wind
- Fuel Cells
- Wave
- Clean Coal (IGCC) & Nuclear

Biomass is combusted in a boiler that generates the steam that drives a steam turbine

Schematic of the Technology



Description

- In a **stoker boiler**, biomass is added in a thin layer on a grate near the bottom of the boiler. This provides a more even distribution of feed material.
  - Mature, most commonly used technology. Incremental improvements being made to increase steam temperature and pressure
- In a **fluidized-bed boiler**, combustors burn biomass fuel in a bed of hot granular material. Air is injected at a high-rate underneath the bed to create the appearance of a boiling liquid. This helps to evenly distribute the fuel.
  - Relatively mature technology - fluidized bed combustors are becoming the systems of choice for biomass fuels, due to good fuel flexibility and good emissions characteristics.

Economic Assumptions: Biomass Combustion – Fluidized Bed Boiler

	Biomass Combustion - Fluidized Bed Boiler Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (MW)	25	From Navigant Consulting sources and estimates.
Project Life (yrs)	25	
Overnight Cost ($/kW)	$2,750	Overnight costs for 2006 are based on the NREL and Oak Ridge National Lab study. Includes all development costs, such as permitting, inventory capital and start-up costs.
Fixed O&M ($/kW-yr)	$145	Fixed O&M costs for 2006 are based on the NREL and OAK Ridge National Lab study. Includes operating, labor and maintenance costs.
Variable O&M ($/MWh)	$3	Non-Fuel Variable O&M costs for 2006 are based on the NREL and OAK Ridge National Lab study. Includes chemicals, water, ammonia, ash disposal.
Fuel Cost ($/MMBtu)	$2.5	Fuel costs assume wood chips at $40/dry ton

Source: "Biomass Strategic Value Analysis – In Support of the 2005 Integrated Energy Policy Report" published by the Energy Research and Development Division, California Energy Commission, June 2005; "BioPower Technical Assessment – State of the Industry and the Technology" published by the National Renewable Energy Lab and Oak Ridge National Lab, June 2003; NCI estimates based on DOE/EPRI Technology Characterizations and NCI multi-client study and interviews

Performance Data: Biomass Combustion – Fluidized Bed Boiler

	Biomass Combustion - Fluidized Bed Boiler Performance Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Scheduled Outage Factor (%)	4%	Scheduled Outage based on approximately 2 weeks/year. This includes a major turbine/generator overhaul every six years lasting one month, 5-7 days of annual for cleaning, tube repairs, etc and 2 days for inspections. 6% forced outage based on interviews.
Forced Outage Rate (%)	6%	
Net Capacity Factor (%)	85%	Based on the California Energy Commission Biomass Strategic Value Analysis, In Support of the 2005 Integrated Energy Policy Report .
HHV Efficiency (%)	22%	HHV = Higher Heating Value. NCI estimate based on review of above mentioned studies and interviews.
Annual Output Degradation (%/yr)	0.4%	From Navigant Consulting sources and estimates.
CO_2 (lb/MWh)	Biomass Combustion is assumed to be CO_2 neutral. SB 1368 contains provisions recognizing the net emission, whole-fuel cycle character of Biomass.	
NO_x (lb/MWh)	1.24	Based on NO_X emissions of 0.08 lbs/MMBtu fuel input as indicated by equipment suppliers. This is better than the CARB recommended BACT guidelines of a limit for NO2 in exhaust of 70 ppm at 12% CO_2 (0.128 lbs/MMBtu) for solid biomass fuel firing. See (http://www.arb.ca.gov/drdb/sac/curhtml/r411.pdf) Page 6.
SO_x (lb/MWh)	0.70	Based on sulfur content in the biomass of 0.03%. Only 60% of the sulfur is converted to SO_2 due to the addition of SO_x control minerals in the fluidized bed. This is lower than typical requirements in CA for sulfur dioxide emissions from the combustion of solid and solid-derived fuels for power generation. See (http://www.arb.ca.gov/drdb/sd/curhtml/r260-43a.htm)

Source: "Biomass Strategic Value Analysis – In Support of the 2005 Integrated Energy Policy Report" published by the Energy Research and Development Division, California Energy Commission, June 2005; "BioPower Technical Assessment – State of the Industry and the Technology" published by the National Renewable Energy Lab and Oak Ridge National Lab, June 2003; NCI estimates based on DOE/EPRI Technology Characterizations and NCI multi-client study and interviews.

Economic Assumptions: Biomass Combustion – Stoker Boiler

	Biomass Combustion – Stoker Boiler Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (MW)	25	From Navigant Consulting sources and estimates.
Project Life (yrs)	25	
Overnight Cost ($/kW)	$2,500	Based on the California Energy Commission study, we assumed that capital costs are marginally lower than for the fluidized bed boiler case.
Fixed O&M ($/kW-yr)	$130	Based on the California Energy Commission study, we assumed that Fixed O&M costs for a stoker boiler are 10% lower than for a fluidized bed boiler.
Variable O&M ($/MWh)	$3	Non-Fuel Variable O&M are assumed to be the same for a stoker boiler system as for a fluidized bed boiler system
Fuel Cost ($/MMBtu)	$2.5	Fuel costs assume wood chips at $40/dry ton.

Source: "Biomass Strategic Value Analysis – In Support of the 2005 Integrated Energy Policy Report" published by the Energy Research and Development Division, California Energy Commission, June 2005; "BioPower Technical Assessment – State of the Industry and the Technology" published by the National Renewable Energy Lab and Oak Ridge National Lab, June 2003; NCI estimates based on DOE/EPRI Technology Characterizations and NCI multi-client study and interviews

Performance Data: Biomass Combustion – Stoker Boiler

	Biomass Combustion – Stoker Boiler Performance Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Scheduled Outage Factor (%)	4%	Scheduled Outage based on approximately 2 weeks/year. This includes a major turbine/generator overhaul every six years lasting one month, 5-7 days of annual for cleaning, tube repairs, etc and 2 days for inspections. 6% forced outage based on interviews.
Forced Outage Rate (%)	6%	
Net Capacity Factor (%)	85%	Based on the California Energy Commission Biomass Strategic Value Analysis, In Support of the 2005 Integrated Energy Policy Report .
HHV Efficiency (%)	21.5%	HHV = Higher Heating Value. NCI estimate based on review of above mentioned studies and interviews. 0.5% lower than for fluidized bed boiler based on discussions with technology providers.
Annual Output Degradation (%/yr)	0.4%	Based on a total output degradation over the lifetime of the project (25 years) of ~2% (same for fluidized bed boiler). Based on NCI estimates, interviews and review of the following documents: http://www.cpuc.ca.gov/Published/Comment_resolution/54445.htm and http://www.calwea.org/Attached%20Documents/Recd%2004Mar05/CALWEA-CBEA-%20CCC%20comments%20on%20the%20MPR%20Staff%20Report%202-28-05.pdf.
CO_2 (lb/MWh)	Biomass Combustion is assumed to be CO_2 neutral. This is SB 1368 contains provisions recognizing the net emission, whole-fuel cycle character of Biomass.	
NO_x (lb/MWh)	1.24	Based on NO_X emissions of 0.08 lbs/MMBtu fuel input as indicated by equipment suppliers. This is better than the CARB recommended BACT guidelines of a limit for NO_2 in exhaust of 70 ppm at 12% CO_2 (0.128 lbs/MMBtu) for solid biomass fuel firing. See (http://www.arb.ca.gov/drdb/sac/curhtml/r411.pdf) Page 6.
SO_x (lb/MWh)	1.10	Based on sulfur content in the biomass of 0.03%. All the sulfur is converted to SO_2. And see Slide 22.

Source: "Biomass Strategic Value Analysis – In Support of the 2005 Integrated Energy Policy Report" published by the Energy Research and Development Division, California Energy Commission, June 2005; "BioPower Technical Assessment – State of the Industry and the Technology" published by the National Renewable Energy Lab and Oak Ridge National Lab, June 2003; NCI estimates based on DOE/EPRI Technology Characterizations and NCI multi-client study and interviews.

Methodology and Key Assumptions: Biomass Combustion

Methodology & Key Assumptions

- For all years we are profiling a 25 MW_E steam boiler fueled by wood chips and associated steam turbine for power generation.
- Capital Costs:
  - For a **fluidized bed boiler system**, the NREL and Oak Ridge National Lab reports capital costs of $2,426/kW for 2001. NCI adjusted this figure for inflation (inflator of 1.15), that resulted in $2,750/kW for 2006.
  - The California Energy Commission study indicates that capital costs for a **stoker boiler** system are 15% lower than for a fluidized bed boiler system in 2006. Based on our interviews, we estimate that the cost differential is 10%, or ~$250/kW in 2006.

- Fixed O&M Costs:
  - For a **fluidized bed boiler**, the NREL and Oak Ridge National Lab study reports total yearly costs of $3.1M in 2001, or $125/kW-yr. Using the above-mentioned inflator to 2006 we obtain $145/kW-yr
  - For a fluidized bed boiler system, to estimate costs for future years, we applied to the 2006 numbers a cost reduction curve from the California Energy Commission study.
  - Based on the California Energy Commission study, we assumed that Fixed O&M costs for a **stoker boiler** are 10% lower than our estimates for a fluidized bed boiler throughout the timeframe.

Methodology and Key Assumptions: Biomass Combustion

Methodology & Key Assumptions

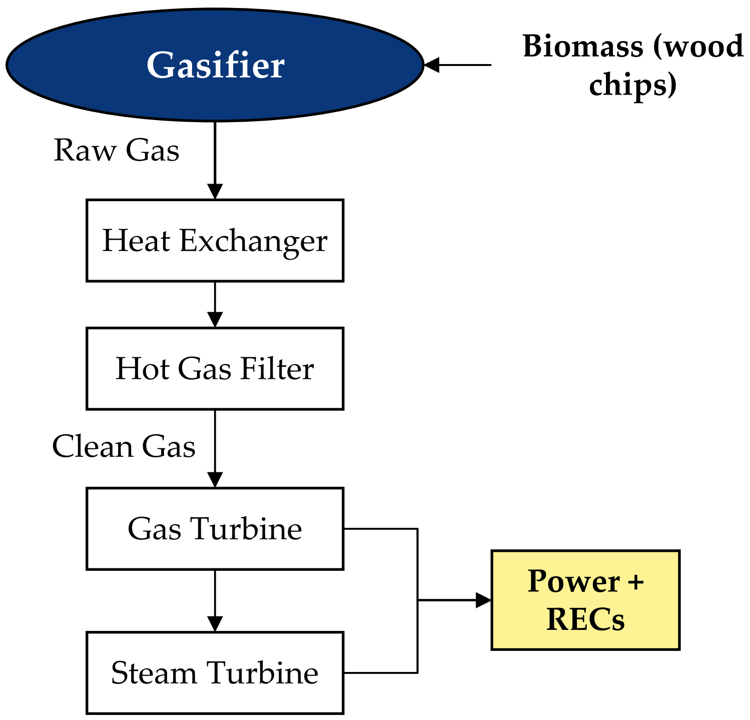
- Non-Fuel Variable O&M Costs: The NREL and Oak Ridge National Lab study reports total yearly costs of $560k in 2001, or $3/MWh. We did not apply and inflation factor and used this same assumption for fluidized bed boilers and stoker boilers alike.
- System HHV Efficiency. NCI estimate. The efficiencies in the California Energy Commission study appear low for the state-of-the-art technologies in the short-term. The NREL and Oak Ridge National Lab study projects higher efficiencies that reflect the use of a biomass drier and steam cycle efficiencies improvements, e.g, higher pressure, higher temperature and reheat (these make sense only for larger plant sizes). Based on interviews, NCI estimates an efficiency of 22% for a 25 MW_E plant in 2006 that will improve only marginally as the technology is mature. Stoker boilers are assumed to have a slightly lower efficiency due to a lower carbon burnout
- Compared to a stoker boiler system a fluidized-bed boiler:
  - Achieves a higher carbon burn-out.
  - Ensures more fuel flexibility due to the good mixing that occurs on the fluidized bed.
  - The relatively low combustion temperature ensures reduced NO_x emissions, and the CFB process allows for the addition of certain minerals into the bed to control SO_x emissions. We estimate a 40% reduction in SO_x emissions compared to the stoker boiler system.

Technology Profiles

- Biomass Biogas
- Biomass Combustion
- **Biomass - Gasification (BIGCC)**
- Geothermal
- Hydro
- Concentrating Solar
- Photovoltaics
- Wind
- Fuel Cells
- Wave
- Clean Coal (IGCC) & Nuclear

Biomass is gasified to produce a syngas that fuels a combined cycle power generation facility

Schematic of the Technology



Description

- This technology gives biomass access to the higher efficiencies of gas fired power generation and combined cycles
- Key characteristics of the system we will profile
  - Direct (single stage and autothermal), pressurized, fluidized bed gasifier
  - Heat exchanger to 400C prior to hot gas filter for dust removal (tar removal is not necessary)
  - Cleaned gas is a combusted in a gas turbine, which also supplies the gasifier with pressurized air from the compressor
  - Residual heat is used in a steam cycle
- Commercial deployment of the technology has not occurred. One demonstration BIGCC unit has been built in Europe but it is no longer in operation.
  - Information on actual capital and operating costs is limited

NAVIGANT CONSULTING

Economic Assumptions: BIGCC

	BIGCC Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (MW)	20	From Navigant Consulting sources and estimates.
Project Life (yrs)	25	
Overnight Cost ($/kW)	$2,800	
Fixed O&M ($/kW-yr)	$150	
Non-Fuel Variable O&M ($/MWh)	$3	
Fuel Cost ($/MMBtu)	$2.50	

Sources: "Handbook Biomass Gasification" edited by H. Knoef and published by BTG (Biomass Technology Group); "Biomass Strategic Value Analysis – In Support of the 2005 Integrated Energy Policy Report", Energy Research and Development Division, California Energy Commission; 'Cost and Performance Analysis of Three Integrated Biomass Gasification Combined Cycle Power Systems" by K. Craig and M. Mann, National Energy Renewable Lab; 'Fuels and Electricity from biomass with and without CO_2 capture and storage" by E. Larson, R. Williams, H. Jin; "Integrated Gasification Combined Cycle and Steam Injection Gas Turbine Powered by Biomass Joint-Venture Evaluation" by G. Sterzinger at the Economics, Environment and Regulation; "Biomass-Gasifier / Aeroderivative Gas Turbine Combined Cycles: Part A – Technologies and Performance Modeling" by E.D. Larson and S. Consonni; "Renewable Energy Technology Characterizations" TR-109496 Topical Report. Prepared by Office of Utility Technologies, Energy Efficiency and Renewable Energy, U.S. Department of Energy and EPRI; Interviews with Richard Bain, NREL and Mark Paisley, Taylor Biomass Energy

Performance Data: BIGCC

	BIGCC Performance Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Scheduled Outage Factor (%)	6%	Based on the BTG study, we assumed a total downtime of 12%.
Forced Outage Rate (%)	6%	
Net Capacity Factor (%)	85%	From Navigant Consulting sources and estimates.
HHV Efficiency (%)	32%	
Annual Output Degradation (%/yr)	0.4%	
CO_2 (lb/MWh)	BIGCC is assumed to be CO_2 neutral. SB 1368 contains provisions recognizing the net emission, whole-fuel cycle character of Biomass.	
NO_x (lb/MWh)	0.85	See comments on section on biomass combustion technologies (stoker boiler and fluidized bed boiler) for further details.
SO_x (lb/MWh)	0.75	

Sources: "Handbook Biomass Gasification" edited by H. Knoef and published by BTG (Biomass Technology Group); "Biomass Strategic Value Analysis – In Support of the 2005 Integrated Energy Policy Report", Energy Research and Development Division, California Energy Commission; 'Cost and Performance Analysis of Three Integrated Biomass Gasification Combined Cycle Power Systems" by K. Craig and M. Mann, National Energy Renewable Lab; 'Fuels and Electricity from biomass with and without CO_2 capture and storage" by E. Larson, R. Williams, H. Jin; "Integrated Gasification Combined Cycle and Steam Injection Gas Turbine Powered by Biomass Joint-Venture Evaluation" by G. Sterzinger at the Economics, Environment and Regulation; "Biomass-Gasifier / Aeroderivative Gas Turbine Combined Cycles: Part A – Technologies and Performance Modeling" by E.D. Larson and S. Consonni; "Renewable Energy Technology Characterizations" TR-109496 Topical Report. Prepared by Office of Utility Technologies, Energy Efficiency and Renewable Energy, U.S. Department of Energy and EPRI; Interviews with Richard Bain, NREL and Mark Paisley, Taylor Biomass Energy

Methodology and Key Assumptions: BIGCC

Methodology & Key Assumptions

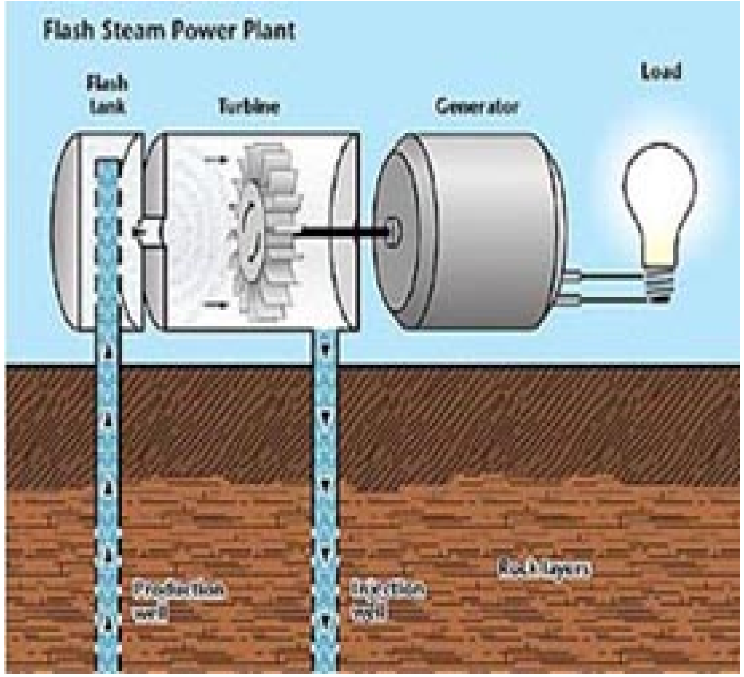
- BIGCC is not a commercial technology. In addition to the direct, pressurized, fluidized bed gasifier, other advanced biomass gasification designs are being studied. Promising options include two-stage (indirect) gasifiers and oxygen-blown gasifiers. It is unclear which variant will prove most cost-competitive in the long-term.
- For 2006 we used as a reference **a collaborative study conducted by BTG biomass technology group BV**, a European firm specialized in bioenergy technologies. Other studies indicate lower capital and operating costs but refer to longer-term economics that incorporate learning curves and other improvements in the technology. The BTG study incorporates the experience of the few operating demonstration units to estimate the current cost for a turnkey BIGCC facility.
  - Unit has 20 MW_E capacity, a capacity factor of 85% and a HHV of 32% (lower than what is assumed in the study based on result of the interviews NCI conducted)
  - Capital costs estimated at $2,800/kW. Major cost items are the gasification island, inclusive of the gasifier, gas cleaning, heat exchangers, etc.. ($1,200/kW) and the gas turbine ($600/kW).
  - Fixed O&M, estimated at $150/kW-yr, include labor (18 people, $50/kW-yr) and maintenance (2% investment, $50/kW-yr).
  - Non-fuel variable O&M, estimated at $3/MWh, include chemicals, water consumption and disposal of residues.
  - Fuel costs of $2.5/MMBtu reflects a cost of $40/ton of wood chips.

Technology Profiles

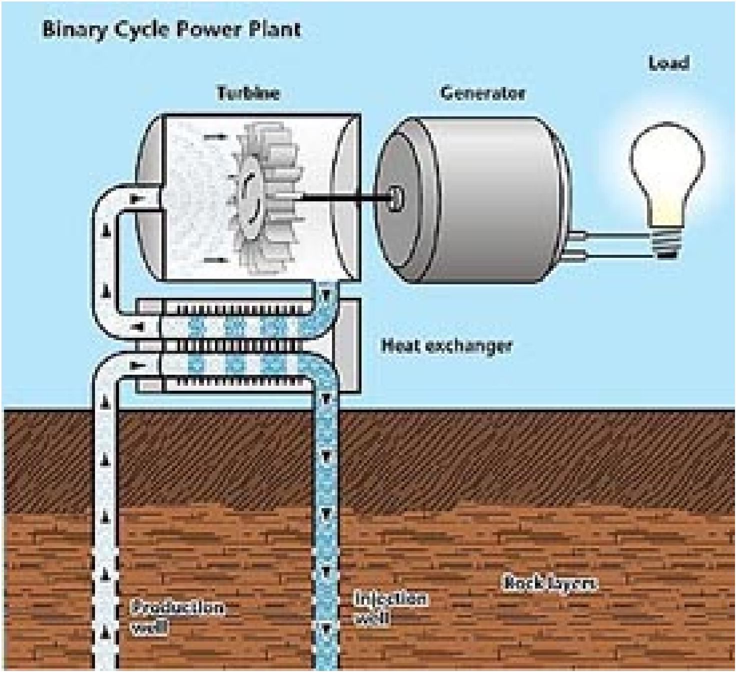
- Biomass - Biogas
- Biomass – Combustion
- Biomass – Gasification (BIGCC)
- **Geothermal**
- Hydro
- Concentrating Solar
- Photovoltaics
- Wind
- Fuel Cells
- Wave
- Clean Coal (IGCC) & Nuclear

Dual Flash systems typically use steam above 400 F and Binary Steam systems use steam below 400 F.

Dual Flash Schematic



Binary Steam Schematic



Source: National Renewable Energy Lab

Economic Assumptions: Geothermal – Dual Flash

	Geothermal – Dual Flash Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (MW)	50	Current California installations range from .5 to 90 MW in size. 50 is an average.
Project Life (yrs)	20	From Navigant Consulting sources and estimates.
Overnight Installed Cost ($/kW)	$2,750	
Exploration ($/kW)	$10	
Confirmation Drilling ($/kW)	$290	
Equipment/Installation ($/kW)	$2,345	
Transmission ($/kW)	$105	
Fixed O&M ($/kW-yr)	$80	
Variable O&M ($/MWh)	$5	Water for cooling condensers is the largest component of Variable O&M. Water access issues in California could balance out any gains in water usage efficiency.

Sources: Navigant Consulting Estimates 2007, Geothermal Strategic Value Analysis CEC-500-2005-105-SD June 2005, Potential Improvements to Existing Geothermal Facilities in California, GRC Transactions, Vol. 30, 2006, J. Lovekin, S. Sanyal, A, Caner Sener, V. Tiangco, and P. Gutierrez-Santana, Interview with Dan Schochet, Vice President of ORMAT Technologies, January 2007, Jim Lovekin of Geothermex, February 2007 and Vince Signorotti of Cal Energy, March 2007.

Performance Data: Geothermal – Dual Flash

	Geothermal – Dual Flash Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Typical Net Capacity Factor (%)	95%	From Navigant Consulting sources and estimates.
Fuel Cost ($/MMBtu)	n/a	
Heat Rate (HHV)	n/a	
HHV Efficiency (%)	n/a	
Annual Output Degradation (%/yr)	4%	
CO_2 (lb/MWh)	60	CO_2 and SO_x are emitted from the geothermal resource. See page 115 of the Geothermal Resource Council Bulletin May-June '05.
NO_x (lb/MWh)	0	
SO_x (lb/MWh)	0.35	

Sources: Navigant Consulting Estimates 2007, Geothermal Strategic Value Analysis CEC-500-2005-105-SD June 2005, Potential Improvements to Existing Geothermal Facilities in California, GRC Transactions, Vol. 30, 2006, J. Lovekin, S. Sanyal, A, Caner Sener, V. Tiangco, and P. Gutierrez-Santana, Interview with Dan Schochet, Vice President of ORMAT Technologies, January 2007. Geothermal Resource Council Bulletin May-June 2005.

Methodology and Key Assumptions: Geothermal – Dual Flash

Methodology & Key Assumptions

- Output and overnight costs can very significantly by site, depending on resource quality. Average values for California are reported.
- NCI surveyed cost and performance data from recent CEC reports on geothermal technology in California. NCI also used internal sources and Energy Velocity. This data was verified by an interview with Vince Signorotti of Cal Energy.
- Future costs are highly uncertain. Costs are assumed to remain constant in real terms as technology advances are balanced by the increased costs of developing relatively less attractive sites.

Economic Assumptions: Geothermal – Binary Steam

	Geothermal – Binary Steam Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (MW)	50	Current California installations range from .5 to 90 MW in size. 50 is an average.
Project Life (yrs)	20	From Navigant Consulting sources and estimates.
Overnight Installed Cost ($/kW)	$3,000	From Navigant Consulting sources and estimates.
Exploration ($/kW)	$8	
Confirmation Drilling ($/kW)	$327	
Equipment/Installation ($/kW)	$2,560	
Transmission ($/kW)	$105	
Fixed O&M ($/kW-yr)	$70	
Variable O&M ($/MWh)	$4.5	Water for cooling condensers is the largest component of Variable O&M. Water access issues in California could balance out any gains in water usage efficiency.

Sources: Navigant Consulting Estimates 2007, Geothermal Strategic Value Analysis CEC-500-2005-105-SD June 2005, Potential Improvements to Existing Geothermal Facilities in California, GRC Transactions, Vol. 30, 2006, J. Lovekin, S. Sanyal, A, Caner Sener, V. Tiangco, and P. Gutierrez-Santana, Interview with Dan Schochet, Vice President of ORMAT Technologies, January 2007

Performance Data: Geothermal – Binary Steam

	Geothermal – Binary Steam Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Typical Net Capacity Factor (%)	95%	From Navigant Consulting sources and estimates.
Fuel Cost ($/MMBtu)	n/a	
Heat Rate (HHV)	n/a	
HHV Efficiency (%)	n/a	
Annual Output Degradation (%/yr)	4%	From Navigant Consulting sources and estimates.
CO_2 (lb/MWh)	0	Binary steam systems do not emit CO_2, NO_x, or SO_x because the geothermal steam is in a closed loop system and is not vented to the atmosphere.
NO_x (lb/MWh)	0	
SO_x (lb/MWh)	0	

Sources: Navigant Consulting Estimates 2007, Geothermal Strategic Value Analysis CEC-500-2005-105-SD June 2005, Potential Improvements to Existing Geothermal Facilities in California, GRC Transactions, Vol. 30, 2006, J. Lovekin, S. Sanyal, A, Caner Sener, V. Tiangco, and P. Gutierrez-Santana, Interview with Dan Schochet, Vice President of ORMAT Technologies, January 2007

Methodology and Key Assumptions: Geothermal – Binary

Methodology & Key Assumptions

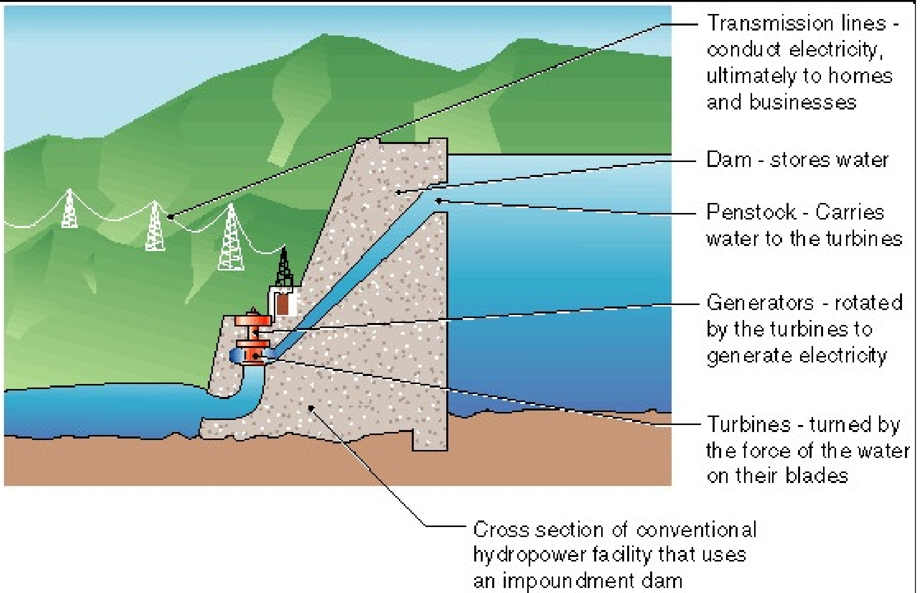
- Output and overnight costs can vary significantly by site, depending on resource quality. Average values for California are reported.
- NCI surveyed cost and performance data from recent CEC reports on geothermal technology in California. NCI also used internal sources and Energy Velocity. This data was verified by an interview with Dan Schochet of ORMAT, Inc. ORMAT is one of the key companies installing plants in California.
- Future costs are highly uncertain. Costs are assumed to remain constant in real terms as technology advances are balanced by the increased costs of developing relatively less attractive sites. Further development in California will require more wells and new drilling techniques to utilize the lower temperature steam.

Technology Profiles

- Biomass - Biogas
- Biomass – Combustion
- Biomass – Gasification (BIGCC)
- Geothermal
- **Hydro**
- Concentrating Solar
- Photovoltaics
- Wind
- Fuel Cells
- Wave
- Clean Coal (IGCC) & Nuclear

A small-scale hydropower facility captures the energy of falling water to generate electricity.

Schematic of the Technology



Description

- The most common type of hydroelectric power plant is an impoundment facility. An impoundment facility, typically a large hydropower system, uses a dam to store river water in a reservoir. Water released from the reservoir flows through a turbine, spinning it, which in turn activates a generator to produce electricity. The water may be released either to meet changing electricity needs or to maintain a constant reservoir level.
- Small Scale Hydropower facilities are impoundment facilities that generate between .01 to 30 MW of electricity.

Sources: Idaho National Laboratory, http://hydropower.inel.gov/hydrofacts/hydropower_facilities.shtml

Economic Assumptions: Small-Scale Hydropower

	Small-Scale Hydropower Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (MW)	10	According to INEEL, the average MW potential at Sites with developed dams without hydropower is 14 MW.
Project Life (yrs)	30	From Navigant Consulting sources and estimates.
Overnight Cost ($/kW)	$4,000	Actual installed costs vary widely based on the amount of civil works and mitigation required. NCI cost estimates are based on Idaho National Lab and RETScreen estimates for a 10MW facility where the damn is already in place.
Equipment & Construction ($/kW)	$1,800	
Licensing & Mitigation ($/kW)	$2,200	
Non-Fuel Fixed O&M ($/kW-yr)	$13	Median cost for plants 8-11 MWs with Dams and No Power in IHRED Database is $13/kW-yr.
Non-Fuel Variable O&M ($/MWh)	$3	Median cost for plants 8-11 MWs with Dams and No Power in IHRED Database is $14.5/kW-yr.
Typical Net Capacity Factor (%)	52%	Idaho National Laboratory estimates.
Annual Output Degradation (%/yr)	2%	From Navigant Consulting sources and estimates.

Sources: Navigant Consulting Estimates 2007. Idaho National Laboratory "Estimation of Economic Parameters of U.S. Hydropower Resources“, June 2003; INEEL Hydropower Resource Economics Database (IHRED); "California Small Hydropower and Ocean Wave Energy Resources"; 2005 IEPR, April 2005; Natural Resources Canada RETScreen® Energy Model - Small Hydro Project; INL State Resource Assessment.

Methodology and Key Assumptions: Small-Scale Hydropower

Methodology & Key Assumptions

- The costs of a small-scale hydropower facility vary widely depending on the amount of civil works, licensing, and mitigation required.
- The Idaho National Laboratory (INL) as well as the Natural Resources Canada (NRC) both have online tools that help estimate the costs for hydropower.
- The Idaho National Laboratory has a database of prospective sites that 1) already have power, 2) are developed with a dam, but do not have power, and 3) are not developed. This analysis focuses on estimating costs for the sites that are developed, but do not have power. The median size of these sites in California is approximately 10 MW.
- Both online tools from the INL and NRC estimate that installed costs in 2002/3 would be approximately $1,500/kW for equipment and construction. INL also estimates costs for mitigation and licensing, which run about $1,750/kW. Based on NCI experience, NCI assumes a 30% increase in costs to arrive at a $4,000/kW installed costs in 2006.
- According to INL, "Estimated costs included in the database including licensing, construction, mitigation, and O&M were not developed by performing individual site analyses. They are general cost estimates based on a collection of historical experience for similar facilities. Therefore, the costs presented in this study should not be interpreted as precise engineering estimates. Actual costs for any specific site could vary significantly from these generalized estimates".

In-Conduit Hydropower facility.

Schematic of the Technology

Description

- In-conduit hydro is that developed within man-made conduits instead of natural streams, rivers, or creeks.
- Key advantages of in-conduit hydropower include no impact on wildlife, reduced O&M due to the cleanliness of the water, more streamlined permitting processes, and often less civil works.
- "Man-made conduits" include pipelines, aqueducts, irrigation ditches, and canals.
- In-conduit hydro can use impoundment, run-of-river, or diversion to generate electricity.

Economic Assumptions: In-Conduit Hydropower

	In-Conduit Hydropower Economic Assumptions for Given Year of Installation (2006$)	
	2006	Notes
Plant Capacity (MW)	1	According to the June 2006 PIER report, the median size is approximately 1 MW for small hydropower.
Project Life (yrs)	30	From Navigant Consulting sources and estimates.
Overnight Cost ($/kW)	$1,500	Actual installed costs vary widely NCI cost estimates are based on Table 7 of the CEC PIER report “Statewide Small Hydropower Resource Assessment”, and adjusted to $2006.
Non-Fuel Fixed O&M ($/kW-yr)	-	
Non-Fuel Variable O&M ($/MWh)	$13	
Typical Net Capacity Factor (%)	49%	
Annual Output Degradation (%/yr)	1%	From Navigant Consulting sources and estimates.

Sources: Navigant Consulting Estimates 2007. CEC PIER "Statewide Small Hydropower Resource Assessment"; PIER Final Project Report, June 2006.

Methodology and Key Assumptions: In-Conduit Hydropower

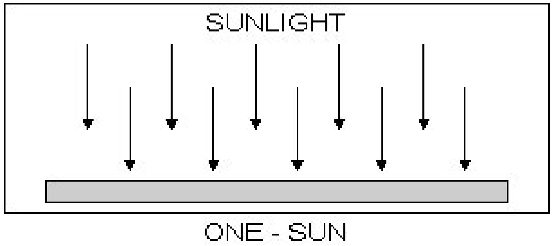
Methodology & Key Assumptions

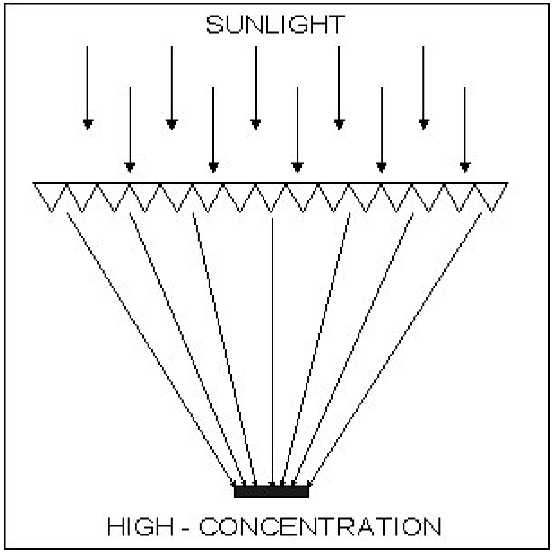
- The costs of a In-Conduit Hydropower were estimated by Navigant Consulting in 2006. ("Statewide Small Hydropower Resource Assessment"; PIER Final Project Report; June 2006; http://www.energy.ca.gov/2006publications/CEC-500-2006-065/CEC-500-2006-065.PDF)
- These estimates are based on that report as well as analysis performed by NCI using the RETScreen cost estimator model developed by Natural Resources Canada.

Technology Profiles

- Biomass - Biogas
- Biomass – Combustion
- Biomass – Gasification (BIGCC)
- Geothermal
- Hydro
- **Concentrating Solar**
- Photovoltaics
- Wind
- Fuel Cells
- Wave
- Clean Coal (IGCC) & Nuclear

Concentrator photovoltaics (CPV) use lenses or reflective collectors to focus solar energy (typically > 100 suns) on a reduced area of solar cell material that is more efficient.





From www.amonix.com

Arizona Public Service photo: Prescott 35 kW, dual axis tracking system.

Installed system costs for concentrating PV are high due to small production volumes.

	Concentrating PV Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Net Plant Capacity (kW)	15,000	Navigant Consulting, Inc. estimates based on Arizona Solar Electric Roadmap, Full Report, Prepared by Navigant Consulting, Inc. for the Arizona Department of Commerce, January 2007 and interview with Vahan Garboushian, President, Amonix, March 7, 2007.
Annual Output Degradation (%/yr)	1%	Interview with Vahan Garboushian, President, Amonix, March 7, 2007. 1% per year up to a maximum of 10% for a system.
Project Life (yrs)	25	Navigant Consulting, Inc. estimates based on Arizona Solar Electric Roadmap, Full Report, Prepared by Navigant Consulting, Inc. for the Arizona Department of Commerce, January 2007 and interview with Vahan Garboushian, President, Amonix, March 7, 2007.
Overnight Cost ($/kWp)	$5,000	
Fixed O&M ($/kW-yr)	$45	
Variable O&M ($/MWh)	NA	
Development Time (months)	12	Interview with Vahan Garboushian, President, Amonix, March 7, 2007.

Sources: "Arizona Solar Electric Roadmap, Full Report", Prepared by Navigant Consulting, Inc, Jan 2007; interview with Vahan Garboushian, President, Amonix, March 7, 2007.

Capacity factors for concentrating PV is estimated around 23% for key areas in Southern California.

	Concentrating PV Economic Assumptions for Given Year of Installation (2006$)	
	2006	Notes
Typical Net Capacity Factor (%)	23%	The systems do not shut down all at once and units are fixed one at a time. Availability is estimated at 98%. Interview with Vahan Garboushian, President, Amonix, March 7, 2007. 1% per year up to a maximum of 10% for a system. Capacity factors based on Arizona Solar Electric Roadmap, Full Report, Prepared by Navigant Consulting, Inc. for the Arizona Department of Commerce, January 2007 and interview with Vahan Garboushian, President, Amonix, March 7, 2007. Capacity factor estimate is typical of Imperial Valley area of Southern California.
Fuel Cost ($/MMBtu)	NA	
HHV Efficiency (%)	NA	
CO_2 (lb/MWh)	No Emissions	
NO_x (lb/MWh)		
SO_x (lb/MWh)		

Sources: "Arizona Solar Electric Roadmap, Full Report", Prepared by Navigant Consulting, Inc, Jan 2007; interview with Vahan Garboushian, President, Amonix, March 7, 2007.

Below are some additional key assumptions and sources used for the Concentrating PV analysis.

Methodology & Key Assumptions

- Companies such as Amonix claim to need 10MW of production volumes to be competitive
  - Arizona Public Service (APS) and Amonix have worked together since 1995 and have >600 kW operating in AZ with 26% efficient cells/250x solar concentration
- The solar rebates that are applicable to flat plate PV in California are not currently applicable to concentrating PV.

A dish/engine uses a mirrored dish (similar to a large satellite dish) that collects and concentrates the sun's heat onto a receiver, which absorbs the heat and transfers it to fluid within the engine.

The heat causes the fluid to expand against a piston or turbine to produce mechanical power. The mechanical power is then used to run a generator or alternator to produce electricity.[1]

1. National Renewable Energy Laboratory web site, March 2007.

Solar Dish engine economics are still somewhat unknown, and vary widely.

	Dish Engine Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Net Plant Capacity (kW)	15,000	From Navigant Consulting sources and estimates.
Annual Output Degradation (%/yr)	NA	Not Available. No commercial systems have been operational enough to provide an estimate.
Project Life (yrs)	25	From Navigant Consulting sources and estimates.
Overnight Cost ($/kWp)	$6,000	
Fixed O&M ($/kW-yr)	$125 - $200	
Variable O&M ($/MWh)	NA	
Development Time (months)	12	From Navigant Consulting sources and estimates.

Sources: "Arizona Solar Electric Roadmap, Full Report", Prepared by Navigant Consulting, Inc, Jan 2007; NCI Interviews.

The capacity factors for Dish Engines are expected to be between 23% – 25% in good solar resource areas in California.

	Dish Engine Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Typical Net Capacity Factor (%)	23% - 25%	Systems may have about 10% of the units not being used as they are in repair. There is therefore expected to be limited forced outage in the near term. Assuming installation near Imperial Valley (Southern California). Low end from interview with NREL and high end based on Arizona Solar Electric Roadmap, Full Report, Prepared by Navigant Consulting, Inc. for the AZ Department of Commerce, January 2007.
Fuel Cost ($/MMBtu)	NA	
HHV Efficiency (%)	NA	
CO_2 (lb/MWh)	No Emissions	
NO_x (lb/MWh)		
SO_x (lb/MWh)		

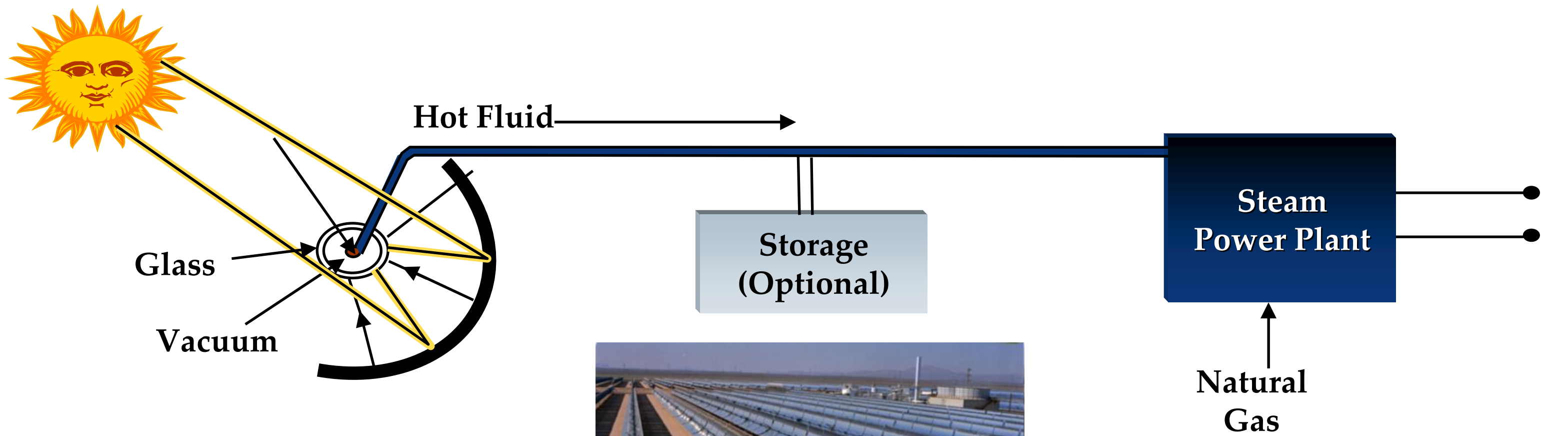
Sources: "Arizona Solar Electric Roadmap, Full Report", Prepared by Navigant Consulting, Inc, Jan 2007; NCI Interviews.

Below are some additional key assumptions and sources used for the Dish Engine analysis.

Methodology & Key Assumptions

- There is limited operational experience for dish Engine technology. Six dishes are in demonstration mode at Sandia and one 25 kW system is operating at the University of NV at Las Vegas.
- SES has a PPA with Southern California Edison for 500 MW with a 350 MW option and a PPA with San Diego Gas & Electric for 300 MWs with a 600 MW option (total potential for 1,750 MW).
- Land use is about 5 acres per MW
- Dish Engines qualify for 5-yr accelerated depreciation and 30% investment tax credit until the end of 2008 when the tax credit amount will reduce to 10%.

Parabolic trough systems use concentrated solar energy to raise the temperature of a heat transfer fluid. Co-firing with NG or storage can sometimes be used to ensure dispatch capability.



Parabolic Trough

Parabolic-trough systems concentrate the sun's energy through long rectangular, curved (U-shaped) mirrors. The mirrors are tilted toward the sun, focusing sunlight on a pipe that runs down the center of the trough. This heats the oil flowing through the pipe. The hot oil then is used to boil water in a conventional steam generator to produce electricity. (NREL web site, March 2007.)

Typical system sizes range are expected to increase, and overnight costs are currently too expensive for more widespread adoption.

	Parabolic Trough Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Gross Plant Capacity (kW)	63,500	NCI estimate based on Solargenix report reference in the source listed below, page 52, and discussions with NREL.
Net Plant Capacity (kW)	50,000	
Annual Output Degradation (%/yr)	0.2%	Based on discussions with NREL.
Project Life (yrs)	30	From Navigant Consulting sources and estimates.
Overnight Cost ($/kWp)	$3,900	Assumes 6 hours of molten salt storage starting in 2010. Navigant Consulting, Inc. estimates for overnight costs based on Black and Veatch report, and discussions with NREL. Data also from report prepared by NCI, Arizona Solar Electric Roadmap Study. Increasing the plant capacity to 100 MW reduces costs ~10%.
Fixed O&M ($/kW-yr)	$60.0	Solar field O&M assumed to be 35% of total O&M and of that 25% is assumed to be for solar field parts and materials (most of which is receiver replacement. Mirror breakage is only 15% of the total parts cost. NCI estimate based on Interview with NREL, Solargenix report, NCI Solar Electric Roadmap for AZ.
Variable O&M ($/MWh)	NA	
Development Time (months)	20	From Navigant Consulting sources and estimates.
Construction Time (months)	12	

Sources: Solar Thermal Parabolic Trough Electric Power Plants for Electric Utilities in California, Prepared by Solargenix Energy for the California Energy Commission, November 2005, CEC-500-2005-175. NCI Interviews with Hank Price and Mark Mehos, NREL. Economic, Energy, and Environmental Benefits of Concentrating Solar Power in California, Prepared by Black and Veatch for the National Renewable Energy Laboratory, April 2006. NREL/SR-550-39291; Arizona Solar Electric Roadmap Study, Prepared by NCI for the AZ Department of Commerce, January 2007 Interview with Bob Lawrence of Sunray Energy, Inc. March 2007.

The solar field that includes the mirrors and the metal support structure is the most costly part of the trough system.

Year	2010
Plant Size	100 MW
Site Work and Infrastructure	1%
Solar Field	45%
Heat Transfer Fluid System	2%
Thermal Energy Storage (6 hrs)	13%
Power Block	8%
Balance of Plant	5%
Contingency	6%
Indirect Costs	20%

Source: Navigant Consulting, Inc. analysis based on Black and Veatch, "Economic, Energy, and Environmental Benefits of Concentrating Solar Power in California", April 2006.

Trough systems currently do not include storage, but by 2010 storage is expected to be an economic option that will increase capacity factors.

	Parabolic Trough Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Scheduled Outage Factor (%)	NA	Defined as solar output less than 75% of maximum during the top 100 hours of peak demand hours. See pg. 36 of Solargenix report. Outage includes 1 week of scheduled outage every year and a 5 week major overhaul every 5 years. Solar plants have the advantage that they can take outages at night or on cloudy days.
Forced Outage Rate (%)	6%	
Typical Net Capacity Factor (%)	27%	A 50 MW system with 6 hrs of storage is being installed in Spain and should be operational by the end of 2007. Assumes 6 hours of molten salt storage starting in 2010. Capacity factors based on discussion with Hank Price, NREL, February 2007.
Fuel Cost ($/MMBtu)	NA	
HHV Efficiency (%)	NA	
CO_2 (lb/MWh)	No Emissions	
NO_x (lb/MWh)		
SO_x (lb/MWh)		

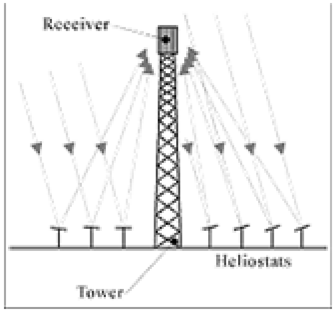
Sources: NCI Estimates 2007. Solar Thermal Parabolic Trough Electric Power Plants for Electric Utilities in California, Prepared by Solargenix Energy for the California Energy Commission, November 2005, CEC-500-2005-175. NCI Interviews with Hank Price, NREL.

Below are some additional key assumptions and sources used for the trough analysis.

Methodology & Key Assumptions

- Trough technology is well proven (without storage)
- Requires high direct normal solar (DNI)
- Overnight cost includes cost of heat collection element, mirrors, metal support structure, heat transfer fluid system, thermal energy storage, and thermal energy storage fluid. Currently, heat collection elements produced in Germany and Israel; and mirrors produced in Germany.
- Also may require water consumption at a rate of 103 million gallons per year. This is for steam cycle, cooling, and washing mirrors. Source: Solar Thermal Parabolic Trough Electric Power Plants for Electric Utilities in California, Prepared by Solargenix Energy for the California Energy Commission, November 2005, CEC-500-2005-175. Page 52.
- 63.5 MW max gross output and 55.5 MW gross output. Net output is 50 MW. Source: Solar Thermal Parabolic Trough Electric Power Plants for Electric Utilities in California, Prepared by Solargenix Energy for the California Energy Commission, November 2005, CEC-500-2005-175. Page 46.
- Construction times at the site are about 1 year. The longest lead time has been the turbine, but from order to on-line for 64 MWe plant is about 20 months. A 100 MW plant will be similar. Component supply can be an issue for large projects, but more receiver and mirror manufacturing facilities are being built. Source: Hank Price, NREL February 26, 2007.

A power tower system uses a large field of mirrors to concentrate sunlight onto the top of a tower, where a receiver sits.



Power Tower

Sunlight heats the molten salt flowing through the receiver. Then, the salt's heat is used to generate electricity through a conventional steam generator. Molten salt retains heat efficiently, so it can be stored for days before being converted into electricity. That means electricity can be produced on cloudy days or even several hours after sunset.[1]

1. National Renewable Energy Laboratory web site, March 2007.

It is unlikely that Power Tower technology can be up and running by 2010, as development time is about 3 – 4 years.

	Power Tower Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Net Plant Capacity (kW)	NA	Based on discussions with NREL March 6,2007. No full scale plants are in operation.
Annual Output Degradation (%/yr)	NA	NCI estimates based on discussions with NREL, 2006; Osuna, et. Al. "PS10, Construction of A 11MW Solar Thermal Tower Plant in Seville, Spain" 2006; Ortega, et. al. "Central Receiver System (CRS) Solar Power Plant Using Molten Salt as Heat Transfer Fluid", 2006; and Sargent and Lundy, "Assessment of Parabolic Trough and Power Tower Solar Technology Cost and Performance Forecasts," 2003; and interview with Mark Mehos, NREL, March 6, 2007.
Project Life (yrs)	NA	
Overnight Cost ($/kWp)	NA	Interview with Mark Mehos, NREL, March 6, 2007.
Fixed O&M ($/kW-yr)	NA	NCI estimates based on discussions with NREL, 2006; Osuna, et. Al. "PS10, Construction of A 11MW Solar Thermal Tower Plant in Seville, Spain" 2006; Ortega, et. al. "Central Receiver System (CRS) Solar Power Plant Using Molten Salt as Heat Transfer Fluid", 2006; and Sargent and Lundy, "Assessment of Parabolic Trough and Power Tower Solar Technology Cost and Performance Forecasts," 2003; and interview with Mark Mehos, NREL, March 6, 2007.
Variable O&M ($/MWh)	NA	
Development Time (Months)	NA	
Construction Time	NA	

Sources: Osuna, et. Al. "PS10, Construction of A 11MW Solar Thermal Tower Plant in Seville, Spain" 2006; Ortega, et. al. "Central Receiver System (CRS) Solar Power Plant Using Molten Salt as Heat Transfer Fluid", 2006; and Sargent and Lundy, "Assessment of Parabolic Trough and Power Tower Solar Technology Cost and Performance Forecasts," 2003; NCI Interviews.

Power Tower technology will likely incorporate 15 hours of storage by 2020 to result in capacity factors of 75%.

	Power Tower Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Forced Outage Rate (%)	NA	Interview with Mark Mehos, NREL March 6, 2007.
Typical Net Capacity Factor for Southern CA (%)	NA	The only plant in construction is the PS10 that is being built in Seville, Spain where the capacity factor in 20%. The Solar Tres plant is designed with 15 hours of storage that is likely to result in capacity factors of 64%. NCI estimates based on Osuna, et. Al. "PS10, Construction of A 11MW Solar Thermal Tower Plant in Seville, Spain" 2006; Ortega, et. al. "Central Receiver System (CRS) Solar Power Plant Using Molten Salt as Heat Transfer Fluid", 2006; and Sargent and Lundy, "Assessment of Parabolic Trough and Power Tower Solar Technology Cost and Performance Forecasts," 2003
Fuel Cost ($/MMBtu)	NA	
HHV Efficiency (%)	NA	
CO_2 (lb/MWh)	No Emissions	
NO_x (lb/MWh)		
SO_x (lb/MWh)		

Sources: Osuna, et. Al. "PS10, Construction of A 11MW Solar Thermal Tower Plant in Seville, Spain" 2006; Ortega, et. al. "Central Receiver System (CRS) Solar Power Plant Using Molten Salt as Heat Transfer Fluid", 2006; and Sargent and Lundy, "Assessment of Parabolic Trough and Power Tower Solar Technology Cost and Performance Forecasts," 2003; NCI Interviews.

Below are some additional key assumptions and sources used for the power tower analysis.

Methodology & Key Assumptions

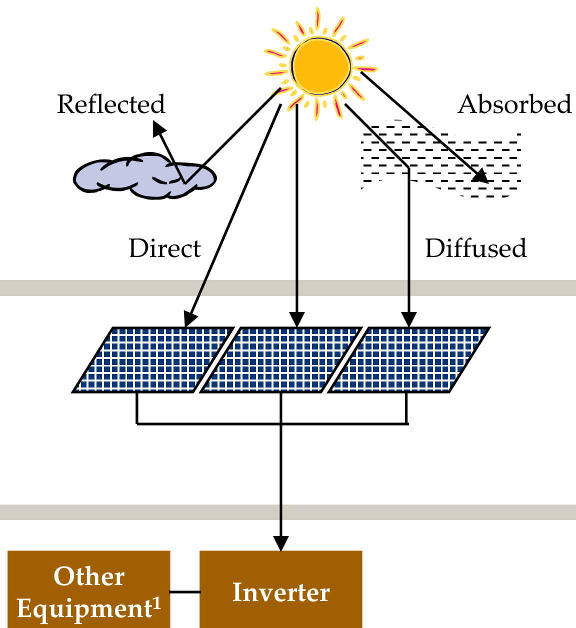
- Power Tower technology has limited field performance experience. The 10 MW Solar One plant operated in Barstow, CA from 1982 to 1988. It was retrofitted with a molten salt receiver and renamed Solar Two from 1998 to 1999.
- PG&E announced plans to buy 500 MW from towers build by LUZ II which are scheduled to be on line in 2010, but here is still only on MOU in place.
- Scales of 50 MW or greater are needed to obtain favorable economics.
- The 30% Investment Tax Credit is applicable until the end of 2008, when it will revert back to 10%.
- The 5-year accelerated depreciation applies to Power Tower technology.
- The degradation is associated with the reflectors and turbines.
- The 11 MW plant in Seville, Spain only has ½ hour of full load storage resulting in about a 25% capacity factor.

Technology Profiles

- Biomass - Biogas
- Biomass – Combustion
- Biomass – Gasification (BIGCC)
- Geothermal
- Hydro
- Concentrating Solar
- **Photovoltaics**
- Wind
- Fuel Cells
- Wave
- Clean Coal (IGCC) & Nuclear

PV technology converts solar energy into usable electrical energy.

From Sun to Power Outlet



Solar Resource	Solar energy falling on a PV module can be either direct or diffused.
PV Panel	DC electrical energy output from PV modules is a function of module operating characteristics and external conditions.
Balance of System (BOS)	AC electrical energy from PV system is a function of system efficiency. An inverter is required to convert DC power to AC
Load	Central station installations are AC electrical and can be fixed, single axis tracking or dual axis tracking.

Rancho Seco
3.9 MW

[1] Other equipment includes mounting structure, switches & fuses, meters, wires & conduits, isolation transformers/ automatic lock-out switches, controls, communication, data acquisition, feeder line connection, and fencing.

NCI has provided business as usual price reductions for central station PV.

Central Station Single Axis Photovoltaics (PV) Economic Assumptions for Given Year of Installation (2006$)		
	2006	**Notes**
Plant Capacity (kWdc)	1,000	From Navigant Consulting sources and estimates.
Annual Output Degradation (%/yr)	0.4%	
Project Life (yrs)	30	
Overnight Cost ($/kWpac)	$9,320	
Development Costs ($/kW)	NA	
Module ($/kWpac)	$4,370	
Inverter ($/kWpac) includes replacements at years 10 & 20	$603.8	
Installation ($/kWpac)	$1,495	
Other BOS ($/kWpac)	$402.5	
Marketing/Sales/Taxes ($/kWpac)	$230	
Gross Margin ($/kWpac)	$2,219.5	
Non-Fuel Fixed O&M ($/kW-yr)	$24	
Non-Fuel Variable O&M ($/MWh)	NA	

Sources: Annual degradation from Tom Hansen, Tucson Electric, February 10, 2007. Overnight costs: provided by several industry representatives: Barry Cinnamon, Akeena Solar; Les Nelson, CALSEIA, and Bill Rever, BP Solar, January 2007. Note: Prices can vary significantly depending on variables such as location, type of owner, and volume of purchase. NCI assumed 80% loss going from DC to AC. Inverter replacement needed every 10 years in out years.

Performance information was based upon an average single axis installation.

	Central Station Single Axis PV Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Scheduled Outage Rate (%)	NA	
Forced Outage Rate (%)	.25%	Inverter is likely to be replaced every 10 years. Source of data is Tom Hansen, Tucson Electric, February 10, 2007. Based on the assumption that the utility will use a sophisticated control systems and therefore forced outages are lower than residential or commercial.
Typical Net Capacity Factor	22.4%	Assumes single axis installation for average insolation levels. Based on output from Clean Power Estimator model.
Fuel Cost ($/MMBtu)	NA	
HHV Efficiency (%)	NA	
CO_2 (lb/MWh)	0.00	
NO_x (lb/MWh)	0.00	
SO_x (lb/MWh)	0.00	

Sources: Annual degradation from Tom Hansen, Tucson Electric, February 10, 2007. Overnight costs: provided by several industry representatives: Barry Cinnamon, Akeena Solar; Les Nelson, CALSEIA, and Bill Rever, BP Solar, January 2007. Note: Prices can vary significantly depending on variables such as location, type of owner, and volume of purchase. NCI assumed 80% loss going from DC to AC. Inverter replacement needed every 10 years in out years.

Below are some additional key assumptions and sources used for the single axis PV analysis.

Methodology & Key Assumptions

- The primary technology installation in 2006 was crystalline silicon technology and therefore some of the early year costs are based on this technology.
- NCI converts all $/Wpdc (direct current) estimates to $/Wpac (alternating current) using a .80 conversion factor to account for module mismatch, inverter efficiency, dust and other losses. This was derived from PVWatts web site and a presentation by Ed Kern, President of Irradiance, *PV Downstream*, Presented in January 2007.
- PV system cost reductions are mostly associated with module efficiency improvements, increased manufacturing capacity, and reductions in inverter prices.
- The net capacity factors factor in dust loss and account for expected hours of output. These estimates were pulled from the Clean Power Estimator model.
- Loan period is 20 years.
- There is currently a 30% Investment Tax Credit for commercial installations that will reduce to 10% after 2008. A 5 year MACRs accelerated depreciation should also be applied to all years of analysis as well as a property tax exemption.
- The 30% ITC does not apply to utility owned systems, however, many utility companies arrange deals with third parties to own, operate, and lease land for the projects (similar to IPP structure).
- Interest during construction is minimal. A 1 MWpdc system could be installed by a crew of eight people in less than eight weeks, based on data from Tucson Electric, February 10, 2007.

Technology Profiles

- Biomass - Biogas
- Biomass – Combustion
- Biomass – Gasification (BIGCC)
- Geothermal
- Hydro
- Concentrating Solar
- Photovoltaics
- **Wind**
- Fuel Cells
- Wave
- Clean Coal (IGCC) & Nuclear

Large, utility wind developments convert wind energy into electricity, and can range from 50 MW to 150 MW in size in California.

Schematic of the Technology

GE 1.5 MW Turbines
Source: GE

GE 3.6 MW Turbines
Source: DOE

Gatun, Spain
49.5 MW wind farm
Source: GE

Description

- A 50 MW wind development consisting of multiple wind turbines atop steel towers. Typical facilities today consist of 1.5 to 2.5 MW turbines atop 80m towers.
- In the future, wind farms are likely to see a continued evolution towards larger rotors, turbine sizes, and tower heights.
- Since installed costs and performance vary with turbine size, tower height and site conditions. NCI assumes some typical turbine sizes, tower heights, and site conditions to develop the cost estimates, recognizing that actual wind farm configurations will see a wider range.
- The expected or typical wind regime is uncertain as new wind developments are likely to be in poorer wind regimes, but re-powering at existing good wind sites like Altamont and Tehachapi is also likely.

NAVIGANT CONSULTING

Methodology and Key Assumptions: Utility Wind

Methodology & Key Assumptions

- NCI based its cost estimates on its knowledge of historical installed costs in the U.S. and California as well as its own internal model of wind installed costs.
- Several leading market participants commented on the NCI cost estimates and helped Navigant refine its numbers.
- Installed costs can vary widely depending on the scale of the project, civil works and interconnection requirements, permitting requirements, and buying power of the owner.
- Future costs are based on a defined wind development size, turbine sizes and tower height, but actual system configurations could differ, which would affect costs and performance.
- Key assumptions include:
  - turbine prices on a $/kW basis decrease asymptotically due to technological improvements and learning;
  - commodity prices increase by 3%/yr in real terms;
  - turbine OEM profit margins will decrease due to increased competition;
  - Balance of plant costs remain constant on a $/kW basis as improvements in scale (capacity rating per tower), are balanced by an increase in cost for interconnection, roads, and the absolute cost per tower.
  - Tower heights increase from 80m to 100m
  - Typical turbine sizes increase from 2 MW to 3.5 MW.
- O&M costs are based on historical performance at existing sites as well as interviews with industry. Costs per unit of capacity and energy are expected to decline as machine size and output increase.

NAVIGANT CONSULTING

Economic Assumptions: Utility Wind

	Utility Wind Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (MW)	50	Based on current proposed projects in California. Source: AWEA.
Turbine Size (range) (MW)	2.0 (1.5-2.5)	From Navigant Consulting sources and estimates.
Tower Height (range) (m)	80 (60 – 80)	
Project Life (yrs)	30	
Overnight Cost ($/kW)	$1,900	Overnight Costs can vary widely depending on the several factors. Key assumptions include: turbine prices on a $/kW basis decrease asymptotically by 1.5%/yr to 0.5%/yr due to technological improvements and learning; commodity prices increase ; turbine OEM profit margins decrease due to increased competition; balance of plant cost increases due to interconnection and increased civil works are mitigated by decreased cost per kW due to increased scale (turbine rating per tower).
Turbine ($/kW)	$1,250	
Balance of Plant / Installation ($/kW)	$500	
Permitting / Development ($/kW)	$150	
Fixed O&M ($/kW-yr)	$30	O&M costs are based on historical performance at existing sites as well as interviews with industry. Costs per unit of capacity and energy are expected to decline as machine size and output increase.

Sources: Navigant Consulting Estimates 2007. AWEA, NCI interviews with leading turbine OEMs, project developers, energy maintenance providers, and wind farm owners.

Performance Data: Utility Wind

	Utility Wind Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Scheduled Outage Factor (%)	0.3%	Forced outage rates and typical capacity factors are based on historical data at existing plants.
Forced Outage Rate (%)	1.3%	
Typical Net Capacity Factor – Class 5 (%)	34%	Wind class definition based on wind speed at 50m: Class 5 = 7.5-8 m/s (16.8-17.9 mph). Capacity factors are net of all losses at the plant (e.g. blade soiling, aerodynamic losses). Expected capacity factors for a given wind regime are expected to remain relatively constant over time. The improvements in turbine design and increased tower heights (factors that increase the capacity factors) are expected to be partially offset by the use of larger machines (which have lower capacity factors).
Annual Output Degradation (%/yr)	0.25%	From Navigant Consulting sources and estimates.
CO_2 (lb/MWh)	No Air Emissions	
NO_x (lb/MWh)		
SO_x (lb/MWh)		

Sources: Navigant Consulting Estimates 2007, AWEA. NCI estimates validated by NCI interviews with leading turbine OEMs, project developers, energy maintenance providers, and wind farm owners.

Technology Profiles

- Biomass - Biogas
- Biomass – Combustion
- Biomass – Gasification (BIGCC)
- Geothermal
- Hydro
- Concentrating Solar
- Photovoltaics
- Wind
- **Fuel Cells**
- Wave
- Clean Coal (IGCC) & Nuclear

Fuel cells convert hydrogen or a hydrogen-rich gas directly to electricity through a clean, efficient electrochemical reaction.

- The main characteristic that distinguishes fuel cell types is the electrolyte. The four principal types being developed for commercial markets are: proton exchange membrane (PEM), phosphoric acid (PAFC), molten carbonate (MCFC), and solid oxide (SOFC).
- Balance of system components include: fuel processor to convert primary fuel to hydrogen or hydrogen rich gas, air handling, water purification / management, power conditioning (to convert DC electricity to AC), heat recovery equipment (for cogeneration applications or hybrid power cycles), and the enclosure.
- Emissions are negligible because fuels are not combusted.[1]
- High efficiency is possible, even at very small scales.

Source: Fuel Cells 2000. Picture of the Fuel Cell Energy MCFC Fuel Cells at Sierra Nevada Brewery in California

1. Typically, a small portion of the unconverted fuel is burned, but with very low emissions.

Broad application of fuel cells is expected to be several years off, but there are some near term opportunities to demonstrate the technology.

- Fuel cells can either use natural gas or carbon-based renewable fuels provided that the gas is properly treated (i.e., contaminants are removed), and reformed into a hydrogen-rich gas.
  - Often have more stringent fuel purity requirements than gas turbines or reciprocating engines.
- Renewable fuels include hydrocarbon-based fuels such as landfill gas, biogas from anaerobic digestion, syngas from biomass gasification and liquid fuels such as ethanol and methanol derived from renewable feedstocks. Hydrogen produced from renewable resources can also be used.
- Low-temperature fuel cells (PEM and PAFC) can also use pure hydrogen. High temperature fuel cells (MCFC and SOFC) are less suited to operation on pure hydrogen and typically internally reform natural gas or other hydrocarbon fuels.
- Key advantages over other small prime movers are: low emissions and high efficiency, but the efficiency advantage is largely lost in LFG and biogas applications because the fuel cost is low or zero.
- United Technologies (UT Fuel Cells) has successfully operated several PC25 200kW PAFC on landfill gas and biogas from wastewater treatment, and offered a standard package for this type of fuel.
  - However, the cost of the PC25 has remained high (>$4,000/kW) and UT Fuel Cells has decided not to invest further in the technology.
- PEM fuel cells are not receiving much attention for biogas or LFG markets.
  - Product sizes are too small for these applications (generally less than 50 kW) and are currently being designed for residential, small commercial and automotive applications.

Technology Description: Molten Carbonate Fuel Cell

- Assumed to be a fuel cell located at a landfill gas fuel to energy (LFGFTE) facility. The 2 MW size was chosen so as to be consistent with the LFGTE technology that uses a reciprocating engine.
- MCFCs are high-temperature fuel cells that use an electrolyte composed of a molten carbonate salt mixture suspended in a porous, chemically inert ceramic matrix of beta-alumina solid electrolyte (BASE). Since they operate at extremely high temperatures of 650°C (roughly 1,200°F) and above, non-precious metals can be used as catalysts at the anode and cathode, reducing costs.
- MCFC systems are high temperature technology (operating temperature 650°C). Uses a liquid alkali carbonate mixture to form the electrolyte layer, nickel based catalyst material and stainless steel cell use for other hardware.
- They have the potential to reach higher electrical efficiencies than that of PEMFC or PAFC.
- Unlike alkaline, phosphoric acid, and polymer electrolyte membrane fuel cells, MCFCs don't require an external reformer to convert more energy-dense hydrocarbons to hydrogen. Due to the high temperatures at which MCFCs operate, these fuels are converted to hydrogen within the fuel cell itself by a process called internal reforming, which also reduces cost.
- Molten carbonate fuel cells are not prone to carbon monoxide "poisoning" - making them more attractive for fueling with gases made from coal.
- The primary disadvantage of current MCFC technology is short stack lifetime. The high temperatures at which these cells operate and the corrosive electrolyte used accelerate component breakdown and corrosion, decreasing cell life. Scientists are currently exploring corrosion-resistant materials for components as well as fuel cell designs that increase cell life without decreasing performance.

Methodology and Key Assumptions: Molten Carbonate Fuel Cell

Methodology & Key Assumptions

- The Molten Carbonate Fuel Cell (MCFC) is modeled after a Fuel Cell Energy product placed in operation at a Landfill Gas Fuel To Energy (LFGFTE) facility. Fue Cell Energy is the largest manufacturer of Molten carbonate fuel cells. The company's Direct Fuel Cell (DFC) products range from 300 kW in size to 2.4 MW.
- Since IEPR assumes a 2MW size for the LFGTE using a reciprocating engine, we assume a similar size for the MCFC. The costs for the MCFC equipment would be higher for system sizes <2MW.
- The MCFC would have similar needs for gas treatment and preparation as well as installation, but it would not require emissions treatment.
- Cost and performance estimates are based on prior NCI experience with fuel cell technology as well as cost and performance estimates published in a 2003 DOE/NREL study: "Gas-fired Distributed Energy Resource Technology Characterizations", DOE/NREL/GTI, October 2003.
- Installed costs for the fuel cell equipment at a landfill are estimated to be higher than one utilizing natural gas due to an approximate 10% de-rating of the output.
- Due to the technological maturity of fuel cells, these cost and performance estimates should be considered within +/- 25% of actual future numbers.

Economic Assumptions: Molten Carbonate Fuel Cell

	Molten Carbonate Fuel Cell Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (kW)	2,000	Assumes the fuel cell is sized for a landfill gas site and utilizes the methane from the landfill.
Project Life (yrs)	20	From Navigant Consulting sources and estimates.
Overnight Cost ($/kW)	$4,350	From Navigant Consulting sources and estimates.
Equipment ($/kW)	$3,600	Based on cost estimates from NREL. Assumes costs decline asymptotically from 3.5% to 1.5%.
Gas Treatment ($/kW)	$300	Similar cost requirements as for a LFGTE facility using a reciprocating engine.
Balance of Plant & Installation ($/kW)	$450	
O&M ($/kW-yr)	$2.10	Based on cost estimates from NREL. Assumes costs decline asymptotically from 3.5% to 1.5%.
Variable O&M ($/MWh)	$35	
Service Contract ($/MWh)	$6	
Stack Replacement ($/MWh)	$29	

Sources: Navigant Consulting Estimates 2007. "Gas-fired Distributed Energy Resource Technology Characterizations", DOE/NREL/GTI, October 2003. Fuel Cell Energy 2006 Annual Report. NCI Interviews with fuel cell manufacturers. "Lessons Learned from the World's Largest Digester Gas Fuel Cell. Washington State Recycling Association -Spokane" May, 2006, Greg Bush -King Co.

Performance Data: Molten Carbonate Fuel Cell

	Molten Carbonate Fuel Cell Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Typical Net Capacity Factor (%)	90%	From Navigant Consulting sources and estimates.
Fuel Cost ($/MMBtu)	n/a	
HHV Efficiency (%)	40%	Based on NREL projections and reported efficiencies at King County 1MW Fuel Cell demonstration project.
CO_2 (lb/MWh)	Assumed to be CO_2 Neutral.	SB 1368 contains provisions recognizing the net emission, whole-fuel cycle character of Biomass.
NO_x (lb/MWh)	0.01	Based on Case Studies cited by Art Soinski, CEC.
SO_x (lb/MWh)	0.003	

Sources: Navigant Consulting Estimates 2007. "Gas-fired Distributed Energy Resource Technology Characterizations", DOE/NREL/GTI, October 2003. Fuel Cell Energy 2006 Annual Report. NCI Interviews with fuel cell manufacturers. "Lessons Learned from the World's Largest Digester Gas Fuel Cell. Washington State Recycling Association -Spokane" May, 2006, Greg Bush -King Co.

Technology Description: Proton Exchange Membrane Fuel Cell

- Assumed to be a 30kW system at a Wastewater Treatment Fuel to Energy (WWTFTE) facility.
- The proton exchange membrane fuel cell (PEMFC) is also known as the solid polymer or polymer electrolyte fuel cell. A PEMFC contains an electrolyte that is a layer of solid polymer (usually a sulfonic acid polymer, whose commercial name is NafionTM) that allows protons to be transmitted from one face to the other. PEMFCs require hydrogen and oxygen as inputs, though the oxidant may also be ambient air, and these gases must be humidified. PEMFCs operate at a temperature much lower than other fuel cells, because of the limitations imposed by the thermal properties of the membrane itself. The operating temperatures are around 90°C. The PEMFC can be contaminated by CO, reducing the performance and damaging catalytic materials within the cell. A PEMFC requires cooling and management of the exhaust water to function properly.

Methodology and Key Assumptions: Proton Exchange Membrane Fuel Cell

Methodology & Key Assumptions

- Several companies manufacture Proton Exchange Membrane (PEM) fuel cells, including Plug Power, United Technologies, Nuvera, and Hydrogenics. Most products are sized at approximately 10 kW to 50 kW. PEM fuel cells are not typically being developed for stationary commercial or industrial power. Instead, manufacturers are targeting the residential and automotive markets.
- In California, potential markets for a stationary PEM fuel cell is a small wastewater treatment facility or a small animal waste anaerobic digester.
- The cost characteristics here are modeled after a 30 kW PEM fuel cell placed in a Wastewater Treatment Fuel to Energy (WWTFTE) facility.
- IEPR assumes a 500 kW size for the WWTFTE facility, but many smaller facilities exist that could be appropriate for a PEM fuel cell. The economics are not as attractive and these markets are not as likely to be targeted by developers, owners, or fuel cell manufacturers.
- Cost and performance estimates are based on prior NCI experience with fuel cell technology as well as cost and performance estimates published in a 2003 DOE/NREL study: "Gas-fired Distributed Energy Resource Technology Characterizations", DOE/NREL/GTI, October 2003.
- Due to the technological maturity of fuel cells, these cost and performance estimates should be considered within +/- 25% of actual future numbers.

Economic Assumptions: Proton Exchange Membrane Fuel Cell

	Proton Exchange Membrane Fuel Cell Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (kW)	30	Assumes the fuel cell is sized for a small wastewater treatment site and utilizes the biogas from the digester.
Project Life (yrs)	20	From Navigant Consulting sources and estimates.
Overnight Cost ($/kW)	$7,000	
Equipment ($/kW)	$6,000	Based on cost estimates from NREL.
Gas Treatment ($/kW)	$550	High level estimate. Actual costs are difficult to determine as PEMs are not typically considered for such applications.
Balance of Plant & Installation ($/kW)	$450	From Navigant Consulting sources and estimates.
Fixed O&M ($/kW-yr)	$18	Based on cost estimates from NREL.
Variable O&M ($/MWh)	$35	
Service Contract ($/MWh)	$13	
Stack Replacement ($/MWh)	$20	

Sources: Navigant Consulting Estimates 2007. "Gas-fired Distributed Energy Resource Technology Characterizations", DOE/NREL/GTI, October 2003. NCI Interviews with fuel cell manufacturers.

Performance Data: Proton Exchange Membrane Fuel Cell

	Proton Exchange Membrane Fuel Cell Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Typical Net Capacity Factor (%)	90%	From Navigant Consulting sources and estimates.
Fuel Cost ($/MMBtu)	n/a	
HHV Efficiency (%)	26%	Assumes a reduction in efficiency as a result of the use of wastewater treatment biogas.
CO_2 (lb/MWh)	Assumed to be CO_2 Neutral	SB 1368 contains provisions recognizing the net emission, whole-fuel cycle character of Biomass.
NO_x (lb/MWh)	<0.1	Based on NREL 2003 report.
SO_x (lb/MWh)	negligible	

Sources: Navigant Consulting Estimates 2007. "Gas-fired Distributed Energy Resource Technology Characterizations", DOE/NREL/GTI, October 2003. NCI Interviews with fuel cell manufacturers.

Technology Description: Solid Oxide Fuel Cell

- Assumed to be a 250 kW system at a Wastewater Treatment Fuel to Energy (WWTFTE) facility.
- Solid oxide fuel cells, or SOFC, are intended mainly for stationary applications with an output from 100 kW to 2 MW. They work at very high temperatures, typically between 700 and 1,000ºC. In these cells, oxygen ions are transferred through a solid oxide electrolyte material at high temperature to react with hydrogen on the anode side. Due to the high operating temperature of SOFC's, they have no need for expensive catalyst, which is the case of proton-exchange fuel cells (platinum). This means that SOFC's do not get poisoned by carbon monoxide and this makes them highly fuel-flexible. Solid oxide fuel cells have so far been operated on methane, propane, butane, fermentation gas, gasified biomass and paint fumes. However, sulfur components present in the fuel must be removed before entering the cell, but this can easily be done by an activated carbon bed or a zinc absorbent.
- Thermal expansion demands a uniform and slow heating process at startup. Typically, 8 hours or more are to be expected. Micro-tubular geometries promise much faster start up times, typically 13 minutes.
- Unlike most other types of fuel cells, SOFC's can have multiple geometries. The planar geometry is the typical sandwich type geometry employed by most types of fuel cells, where the electrolyte is sandwiched in between the electrodes. SOFC's can also be made in tubular geometries where either air or fuel is passed through the inside of the tube and the other gas is passed along the outside of the tube. The tubular design is advantageous because it is much easier to seal and separate the fuel from the air compared to the planar design. The performance of the planar design is currently better than the performance of the tubular design however, because the planar design has a lower resistance compared to the tubular design.

Methodology and Key Assumptions: Solid Oxide Fuel Cell

Methodology & Key Assumptions

- Several companies manufacture Solid Oxide Fuel Cells (SOFC), including GE Power Systems, Rolls Royce, Mitsubishi, Acumentrics, and Siemens/Westinghouse. Most all products are sized at approximately 250 kW, although many of the test products are under 100 kW.
- In California, potential renewable fuels markets for a stationary SOFC is a small wastewater treatment facility or a small animal waste anaerobic digester.
- The cost characteristics here are modeled after a 250 kW SOFC placed in a Wastewater Treatment Fuel to Energy (WWTFTE) facility.
- IEPR assumes a 500 kW size for the WWTFTE facility, but many smaller facilities exist that could be appropriate for a SOFC.
- Cost and performance estimates are based on prior NCI experience with fuel cell technology as well as cost and performance estimates published in a 2003 DOE/NREL study: "Gas-fired Distributed Energy Resource Technology Characterizations", DOE/NREL/GTI, October 2003

Economic Assumptions: Solid Oxide Fuel Cell

	Solid Oxide Fuel Cell Economic Assumptions for Given Year of Installation (2006$)	
	2006	Notes
Plant Capacity (kW)	250	Assumes the fuel cell is sized for a small wastewater treatment site and utilizes the biogas from the digester.
Project Life (yrs)	20	From Navigant Consulting sources and estimates.
Overnight Cost ($/kW)	$4,750	Based on cost estimates from NREL.
Equipment ($/kW)	$3,900	
Gas Treatment ($/kW)	$400	High level estimate. Actual costs are difficult to determine as few SOFCs have been designed for such applications.
Balance of Plant & Installation ($/kW)	$450	From Navigant Consulting sources and estimates.
Fixed O&M ($/kW-yr)	$10	Based on cost estimates from NRE.
Variable O&M ($/MWh)	$24	
Service Contract ($/MWh)	$11	
Stack Replacement ($/MWh)	$13	

Sources: Navigant Consulting Estimates 2007. "Gas-fired Distributed Energy Resource Technology Characterizations", DOE/NREL/GTI, October 2003. NCI Interviews with fuel cell manufacturers.

Performance Data: Solid Oxide Fuel Cell

	Solid Oxide Fuel Cell Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Typical Net Capacity Factor (%)	90%	From Navigant Consulting sources and estimates.
Fuel Cost ($/MMBtu)	n/a	
HHV Efficiency (%)	40%	Assumes a reduction in efficiency as a result of the use of wastewater treatment biogas.
CO_2 (lb/MWh)	Assumed to be CO_2 Neutral[2]	SB 1368 contains provisions recognizing the net emission, whole-fuel cycle character of Biomass.
NO_x (lb/MWh)	<0.05	Based on NREL 2003 report.
SO_x (lb/MWh)	negligible	

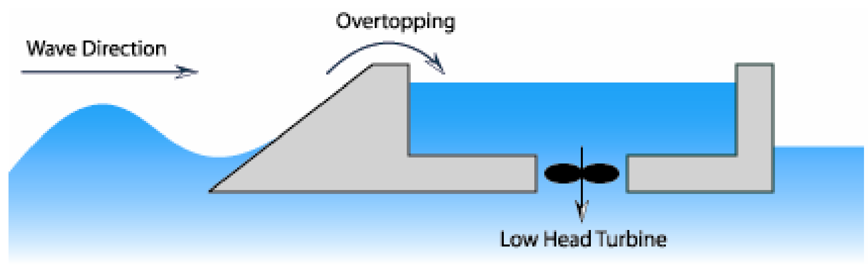
Sources: Navigant Consulting Estimates 2007. "Gas-fired Distributed Energy Resource Technology Characterizations", DOE/NREL/GTI, October 2003. NCI Interviews with fuel cell manufacturers.

Technology Profiles

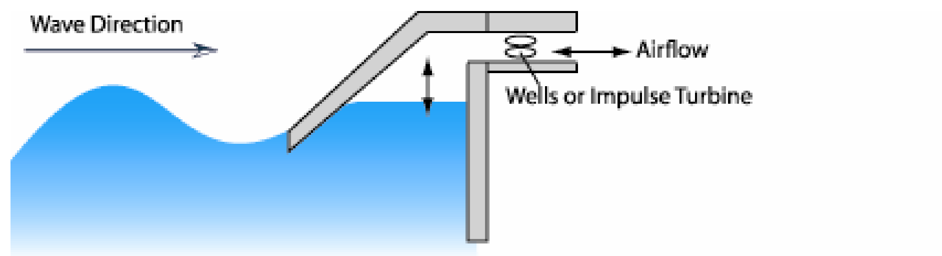
- Biomass - Biogas
- Biomass – Combustion
- Biomass – Gasification (BIGCC)
- Geothermal
- Hydro
- Concentrating Solar
- Photovoltaics
- Wind
- Fuel Cells
- **Wave**
- Clean Coal (IGCC) & Nuclear

Wave Energy Conversion devices convert wave motion to electricity.

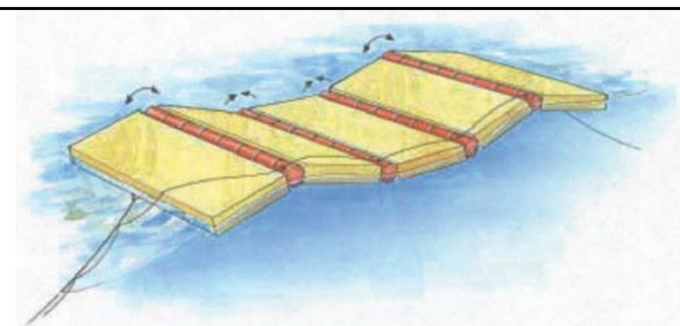
Overtopping



Oscillating Water Column



Buoyant Moored Device



Sources: EPRI

Economic Assumptions: Wave Energy Conversion

	Wave Energy Conversion Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (MW)	.75	The 2006 number assumes a small 750 kW pilot plant.
Project Life (yrs)	20	From Navigant Consulting sources and estimates.
Overnight Installed Cost ($/kW)	$6,970	Assumes 82% progress ratio with worldwide production capacities of 100 MW in 2010.
Transmission and undersea cables	$1,340	From Navigant Consulting sources and estimates.
Equipment	$4,000	
Facilities	0	
Installation	$990	
Construction Management and Permitting	$640	
Fixed O&M ($/kW-yr)	$30	
Non-Fuel Variable O&M ($/MWh)	$25	

Sources: Navigant Consulting Estimates 2007, System Level Design, Performance and Costs – Oregon State Offshore Wave Power Plant - EPRI 2004, Interview with Roger Bedard of EPRI February 2007

Performance Data: Wave Energy Conversion

	Wave Energy Conversion Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Typical Net Capacity Factor (%)	15%	Capacity factors will vary with site conditions.
Fuel Cost ($/MMBtu)	n/a	
Heat Rate (HHV)	n/a	
HHV Efficiency (%)	n/a	
Annual Output Degradation (%/yr)	1%	From Navigant Consulting sources and estimates.
CO_2 (lb/MWh)	0	Wave energy conversion technologies have no emissions.
NO_x (lb/MWh)	0	
SO_x (lb/MWh)	0	

Sources: Navigant Consulting Estimates 2007, System Level Design, Performance and Costs – Oregon State Offshore Wave Power Plant - EPRI 2004, Interview with Roger Bedard of EPRI February 2007

Methodology and Key Assumptions: Wave Energy Conversion

Methodology & Key Assumptions

- No commercial Wave Energy Conversion facilities exist anywhere in the world.
  - Thus, NCI only analyzed a pilot facility for 2006.
- System output varies significantly during the year and from year to year. NCI took yearly total outputs and averaged them over the year.
- NCI used cost data from studies done by EPRI for Wave Energy Conversion facilities built off the Oregon coast. The wave climate closely matches the Northern California locations where PG&E has applied to the FERC for permits.
  - The EPRI paper calculated costs for 100 MW worldwide production capability and an 82% progress ratio for learning curves (based upon wind power, PV, and offshore oil and gas)
  - NCI held transmission, facility, and permitting costs constant for a commercial facility over time.

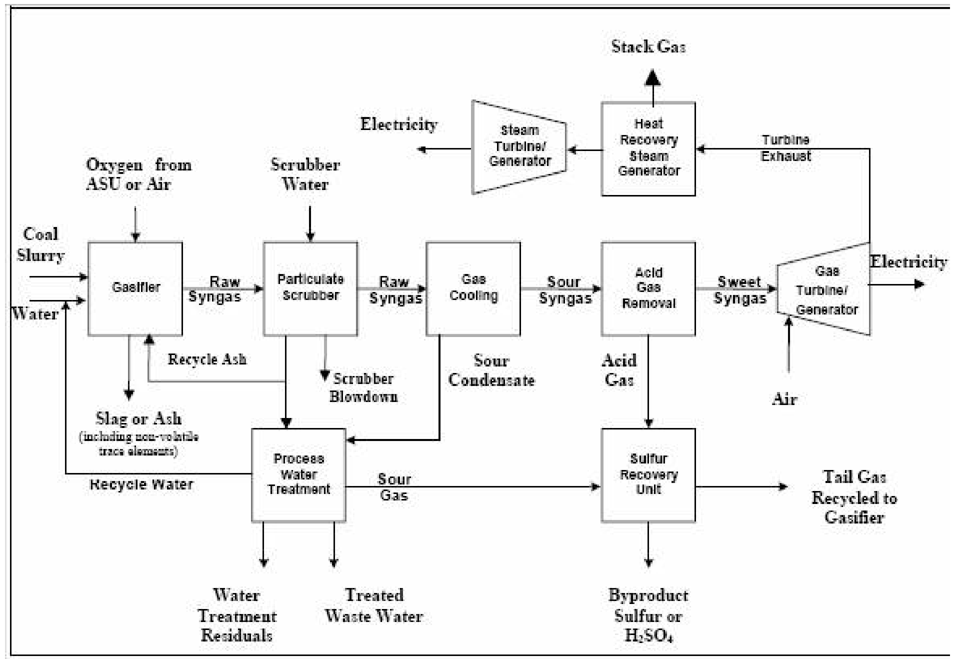
Technology Profiles

- Biomass - Biogas
- Biomass – Combustion
- Biomass – Gasification (BIGCC)
- Geothermal
- Hydro
- Concentrating Solar
- Photovoltaics
- Wind
- Fuel Cells
- Wave
- **Clean Coal (IGCC) & Nuclear**

Integrated Gasification Combined Cycle is a power plant using syngas (developed from coal) as a source of clean fuel.

- Integrated Gasification Combined Cycle, or IGCC, is a power plant using synthetic gas (syngas) as a source of clean fuel. Syngas is produced in a gasification unit built for Combined Cycle purposes. Steam generated by waste heat boilers of the gasification process is utilized to help power steam turbines. Heavy petroleum residues, coal, and even biomass are possible feeds for gasification process.
- IGCC is now being considered since it may offer a low-cost long-term option for the reduction of carbon dioxide emissions (through capture and storage).
- The main inhibiting factor for IGCC is high capital cost, but reliability must also be proven before widespread deployment can occur.

Schematic of Generic IGCC Power Plant



Source: "Advanced Fossil Power Systems Comparison Study – Final Report" Prepared for the National Energy Technologies Laboratory, US Department of Energy.

Methodology and Key Assumptions: IGCC

Methodology & Key Assumptions

- The costs of IGCC power plants using coal have been documented in numerous studies, with estimates for installed costs ranging from $1,400/kW to $2,300/kW. Some of the lower estimates were performed over 5 years ago prior to the recent increase in commodity and steel prices.
- NCI used 4 primary sources for its cost estimates
  - "Integrated Gasification Combined-Cycle Technology Draft Report: Benefits, Costs, and Prospects for Future Use in Wisconsin", dated June 2006 prepared by the Wisconsin Department of Natural Resources and the Public Service Commission of Wisconsin;
  - "2007 Electric Integrated Resource Plan - IRP Modeling Overview: Resource Options and Cost Assumptions", Avista, August 31, 2006, John Lyons.
  - "Annual Energy Outlook 2006, With Projections to 2030", Energy Information Administration, February 2006;
  - EPRI Technical Assessment Guide
- NCI cost estimates for 2006 reflect the higher end of the cost estimates, and are representative of initial test facilities.

Economic Assumptions: IGCC

	IGCC Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (MW)	500	From Navigant Consulting sources and estimates.
Project Life (yrs)	40	
Overnight Cost ($/kW)	$2,050	The WI PUC estimate is $1,885/kW for Wisconsin. NCI assumes $2,050, which reflects a cost adjustment for California. Approximately 1%/yr cost improvement is achieved due to learning and technical change.
Fixed O&M ($/kW-yr)	$35	2006 estimates reflect 2006 Wisconsin PSC IGCC Report estimates, which are more representative of a test facility.
Variable O&M ($/MWh)	$3	

Sources: Navigant Consulting Estimates 2007. EPRI Technical Assessment Guide; Maurstad, O. (2005), "An Overview of Coal-Based Integrated Gasification Combined Cycle (IGCC) Technology". Laboratory for Energy and the Environment, Massachusetts Institute of Technology; "Annual Energy Outlook 2006, With Projections to 2030", Energy Information Administration, February 2006; Parsons, E., Shelton, W. Lyons, L. (2002), "Advanced Fossil Power Systems Comparison Study – Final Report" Prepared for the National Energy Technologies Laboratory, US Department of Energy; Integrated Gasification Combined-Cycle Technology Draft Report: Benefits, Costs, and Prospects for Future Use in Wisconsin, dated June 2006 prepared by the Wisconsin Department of Natural Resources and the Public Service Commission of Wisconsin; "Avista 2007 Electric Integrated Resource Plan - IRP Modeling Overview: Resource Options and Cost Assumptions", August 31, 2006, John Lyons.

Performance Data: IGCC

	IGCC Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Typical Net Capacity Factor (%)	80%	Based on WI PSC and DNR IGCC Study for IGCC plants using western coal.
Fuel Cost ($/MMBtu)	$1.50	
HHV Efficiency (%)	38%	Based on WI PSC and DNR IGCC Study for IGCC plants using western coal. HHV Efficiency for 2006 based on WI PSC and DNR IGCC Study for IGCC plants using western coal. 2030 estimates reflect Nth plant estimates by the EIA. Due to its higher moisture content, western coal requires more heat to convert energy into electricity.
CO_2 (lb/MWh)	1,928	Based on WI PSC and DNR IGCC Study for IGCC plants using western coal. NCI Emissions Calculator
NO_x (lb/MWh)	0.53	
SO_x (lb/MWh)	0.30	

Sources: Navigant Consulting Estimates 2007. EPRI Technical Assessment Guide; Maurstad, O. (2005), “An Overview of Coal-Based Integrated Gasification Combined Cycle (IGCC) Technology”. Laboratory for Energy and the Environment, Massachusetts Institute of Technology; "Annual Energy Outlook 2006, With Projections to 2030", Energy Information Administration, February 2006; Parsons, E., Shelton, W. Lyons, L. (2002), “Advanced Fossil Power Systems Comparison Study – Final Report” Prepared for the National Energy Technologies Laboratory, US Department of Energy; Integrated Gasification Combined-Cycle Technology Draft Report: Benefits, Costs, and Prospects for Future Use in Wisconsin, dated June 2006 prepared by the Wisconsin Department of Natural Resources and the Public Service Commission of Wisconsin; “Avista 2007 Electric Integrated Resource Plan - IRP Modeling Overview: Resource Options and Cost Assumptions", August 31, 2006, John Lyons.

Future nuclear power plants in California could be one of several competing designs, and NCI developed cost estimates for a generic advanced nuclear technology.

Generic Description of Nuclear Power Technology

- Nuclear power is the controlled use of nuclear reactions to release energy for the generation of electricity. Nuclear energy is produced when a fissile material, such as uranium-235 (235U), is concentrated such that nuclear fission takes place in a controlled chain reaction and creates heat — which is used to boil water, produce steam, and drive a steam turbine.

Nuclear Power Technology in California

- Currently, there are three different consortia who are leading efforts to build new nuclear power plants in the United States. None of these consortia have any plans to build a new plant in California.
- Several manufacturers are developing advanced nuclear technology designs. The cost estimates for these designs vary widely. IEPR cost estimates are for a generic advanced nuclear technology.

Advanced Nuclear Design Types and Manufacturers

Design	Mfgr.	Size & Type
ABWR	GE	1,350 MWe BWR
ESBWR	GE	1,380 MWe BWR with passive safety features
SWR 1000	Framatome ANP	1,013 MWe BWR
AP600	BNFL – Westinghouse	610 MWe PWR with passive safety features
AP1000	BNFL – Westinghouse	1090 MWe PWR with passive safety features
IRIS	Westinghouse	100-300 MWe PWR
PBMR	ESKOM	110 MWe modular pebble bed gas-cooled reactor
GT-MHR	General Atomics	288 MWe prismatic graphite moderated gas-cooled reactor
ACR 700	AECL	730 MWe heavy water reactor

Methodology and Key Assumptions: Advanced Nuclear

Methodology & Key Assumptions

- Cost estimates are based on four primary sources
  - "The Future of Nuclear Power. An Interdisciplinary MIT Study", MIT, 2003;
  - "Annual Energy Outlook 2006, With Projections to 2030", Energy Information Administration, February 2006;
  - “Avista 2007 Electric Integrated Resource Plan - IRP Modeling Overview: Resource Options and Cost Assumptions", August 31, 2006, John Lyons;
  - A Press Release for Finnish Utility TVO, December 18, 2003.
- Typical cost estimates are around $2,000 from MIT (see page 135), Avista (see page 16), EIA (see table 38, page 73). Most of these estimates were made prior to recent cost increases in steel and are not applicable to California. NCI assumes $2,400/kW based on recent inflation and relative price differentials for California. This number is more in line with the $2,300/kW order by the Finnish Utility TOV from Areva/Siemens in 2003.
- The MIT Study, performed in 2003, compiled cost statistics from numerous sources, and analyzed the costs of several recent new nuclear power plants in South Korea and Japan
- Other cost and operational data are very consistent across sources. NCI used the MIT or EIA data except where there definitions were not consistent with the California IEPR approach. For example, the Avista O&M costs fit the IEPR definition more closely.

Economic Assumptions: Advanced Nuclear

	Advanced Nuclear Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (kW)	1,000	MIT Future of Nuclear Power.
Project Life (yrs)	40	
Overnight Cost ($/kW)	$2,400	Typical cost estimates are around $2,000 from MIT (see page 135), Avista (see page 16), EIA (see table 38, page 73). Many of these estimates were made prior to recent cost increases in steel and are not applicable to California. NCI assumes $2,400/kW based on recent inflation and relative price differentials for California. This number is more in line with the $2,300/kW order by the Finnish Utility TOV from Areva/Siemens in 2003. Assumes some standardization of design and learning from commercial deployment in the U.S.
Fixed O&M ($/kW-yr)	$55	Avista IRP, EIA, MIT Future of Nuclear Power. Assumes some standardization of design and learning from commercial deployment in the U.S.
Variable O&M ($/MWh)	$1.20	

Sources: Navigant Consulting Estimates 2007. "The Future of Nuclear Power. An Interdisciplinary MIT Study", MIT, 2003; "Annual Energy Outlook 2006, With Projections to 2030", Energy Information Administration, February 2006; “Avista 2007 Electric Integrated Resource Plan - IRP Modeling Overview: Resource Options and Cost Assumptions", August 31, 2006, John Lyons; EIA Electric Power Annual, Table 8.2. Average Power Plant Operating Expenses for Major U.S. Investor-Owned Electric Utilities, 1994 through 2005; Press Release for Finnish Utility TVO, December 18, 2003.

Performance Data: Advanced Nuclear

	Advanced Nuclear Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Typical Net Capacity Factor (%)	85%	MIT Future of Nuclear Power, EIA.
Fuel Cost ($/MMBtu)	$0.50	
HHV Efficiency (%)	32.8%	
CO_2 (lb/MWh)	No Emissions	
NO_x (lb/MWh)		
SO_x (lb/MWh)		

Sources: Navigant Consulting Estimates 2007. "The Future of Nuclear Power. An Interdisciplinary MIT Study", MIT, 2003; "Annual Energy Outlook 2006, With Projections to 2030", Energy Information Administration, February 2006; "Avista 2007 Electric Integrated Resource Plan - IRP Modeling Overview: Resource Options and Cost Assumptions", August 31, 2006, John Lyons; EIA Electric Power Annual, Table 8.2. Average Power Plant Operating Expenses for Major U.S. Investor-Owned Electric Utilities, 1994 through 2005; Press Release for Finnish Utility TVO, December 18, 2003.